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**Commissioner Woodward died on August 4, 1964.

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FOREWORD

The Federal Power Act was originally enacted as the Federal Water Power Act, approved June 10, 1920 (41 Stat. 1063, 16 U.S.C. 791–823). The Federal Power Commission was reorganized January 1, 1931, as an independent Commission under the act approved June 23, 1930 (46 Stat. 797). By title II of the Public Utility Act of 1935, approved August 26, 1935 (49 Stat. 838), the original Federal Water Power Act was made part I of the "Federal Power Act" and parts II and III were added. The Federal Power Act was amended May 28, 1948 (62 Stat. 275), August 7, 1953 (67 Stat. 461), August 15, 1953 (67 Stat. 587), June 4, 1956 (70 Stat. 226), and August 28, 1958 (72 Stat. 941 at 947). The Commission also administers the Natural Gas Act, approved June 21, 1938 (52 Stat. 821, 15 U.S.C. 717–717w), as amended February 7, 1942 (56 Stat. 83, 15 U.S.C. 717f), July 25, 1947 (61 Stat. 459, 15 U.S.C. 717f), March 27, 1954 (68 Stat. 36, 15 U.S.C. 717(c)), and August 28, 1958 (72 Stat. 941 at 947; 15 U.S.C. 717r), and has certain duties under the Tennessee Valley Authority Act, approved May 18, 1933 (48 Stat. 1075), and amendments thereto; the Bonneville Act, approved August 20, 1937 (50 Stat. 731), the Fort Peck Act approved May 18, 1938 (52 Stat. 403); and under various Flood Control and River and Harbor Acts (notably the Flood Control Act of 1944, approved December 22, 1944 (58 Stat. 887)), and other statutes, as well as Executive Orders.

This volume, the twenty-seventh of a series, contains all the formal opinions and accompanying orders of the Federal Power Commission rendered, January 1, 1962 to June 30, 1962, inclusive. In addition to the formal opinions, there have been included intermediate decisions which have become final and selected orders of the Commission issued during such period.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

SHELL OIL COMPANY, DOCKET NO. G–9446, ET AL.

ORDER RESERVING DETERMINATION OF CERTIFIED QUESTIONS PENDING COMPLETION OF HEARING AND EXAMINER'S DECISION

(Issued January 3, 1962)

This matter was brought before the Commission by the presiding examiner's certifying three questions arising in the above-entitled proceedings. The questions involve (1) the propriety of terminating the Section 4(e) and Section 5(a) proceedings under the Natural Gas Act involving Shell Oil Company (Shell) herein; (2) the matter of consolidating the Section 5(a) aspects of this proceeding with the area-rate proceedings; and (3) whether El Paso Natural Gas Co., as a purchaser of Shell's gas is " * * * entitled to a lower rate by reason of the fact that the sole source of the gas received in California originates in an area where the producer's unit production costs are less than its company-wide unit production costs".

The basis upon which the presiding examiner certified these questions is that the direct evidentiary presentations of both the staff and Interveners (the Eastern Seaboard companies and the Southern California companies) indicate that Shell, during the test year 1959, had jurisdictional costs in excess of its jurisdictional revenues. Pending our disposition, the presiding examiner has continued to go forward with the hearing.

Formal responses to the certified questions were timely filed by Shell, Interveners, the California Commission and the staff. Shell expressed a position calling for the termination of these consolidated proceedings; whereas the Interveners, the California Commission and the staff severally expressed opposition to the termination of either the Section 4(e) or Section 5(a) proceedings consolidated herein. Interveners challenged, among other things, the propriety of employing 1959 as the test-year period. The California Commission contended, primarily, that individual rates should be compared with costs on an area basis as well as on a company-wide basis. The staff contended that, because Shell had put into effect substantial increased rates during the latter part of the test year, Shell's test-year costs should be compared not only with its actual revenues but also with its annualized revenues.

A brief review of the procedural and evidentiary background of these proceedings indicate that hearings commenced on July 7, 1960, extended through the direct testimony and cross-examination thereof of all parties' and the staff's witnesses, and encompass sixty-one exhibits and approximately 6,000 transcript pages. All that remains to be completed in the hearing phase of these proceedings is the presentation of Shell's rebuttal case, which is scheduled to be introduced into the record on January 18, 1962, and the subsequent cross-examination thereof.

Pending the completion of the hearings and the presiding examiner's decision, it would appear that our ruling on the merits of the contentions of the various parties and the staff to the certified questions would be premature.

The Commission orders:

Our determination on the certified questions filed herein on November 24, 1961, is hereby reserved pending the completion of the hearing and the presiding examiner's decision; and the hearings herein shall continue as scheduled by the presiding examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

INDEPENDENT PRODUCERS OF NATURAL GAS—FORM OF FILING FOR RATE INCREASES DOCKET NO. R-204

ORDER NO. 240

AMENDING § 154.94 OF REGULATIONS UNDER THE NATURAL GAS ACT

(Issued January 4, 1962)*

The Commission has under consideration in this proceeding the adoption of a single-page form for use by small independent producers (and in certain cases large producers) in submitting for filing proposed changes in rates pursuant to Section 4(d) of the Natural Gas Act. The use of the form will obviate, in most cases, the submission of the full supporting statement now required, thereby lessening the burdens incident to rate filings.

In essence, the amendments to the regulations herein adopted provide that:

(1) Small producers, who sold 5,000,000 Mcf, or less, of gas in interstate commerce annually, in each year of their operations during the preceding five years will use the form without a further supporting statement for any proposed contractual rate change.

(2) Producers who sold more than 5,000,000 Mcf of gas in interstate commerce annually in any year during the preceding five years and are proposing a contractual rate level equal to, or less than, the applicable area price level for increased rates shall submit the information required by the form but need not submit any additional supporting statement.

(3) Producers who sold more than 5,000,000 Mcf of gas in interstate commerce annually in any year during the preceding five years and are proposing a contractual rate change to a level exceeding the announced applicable area rate level and all producers proposing an ex parte or unilateral rate change shall submit the information required by the form and a full supporting statement.

The Commission finds:

(1) Amendment of the regulations as herein ordered is appropriate and necessary for carrying out the provisions of the Natural Gas Act.

(2) The amendments herein ordered represent matters of practice and procedure which do not require notice or hearing under section 4(a) of the Administrative Procedure Act.

The Commission acting pursuant to authority granted by sections 4 and 16 of the Natural Gas Act (15 U.S.C. 717c, 717o), *orders:*

(A) Part 154 of Subchapter E, Regulations Under the Natural Gas Act, Chapter I of Title 18 of the Code of Federal Regulations, is amended as follows:

In § 154.94, subsections (e), (f), and (g) are amended to read as follows—

(e) With each change in rate schedule not constituting a change in rate level by any means there shall be submitted reasons, nature and basis for the proposed change and the date upon which the change is proposed to be made effective. Changes in service such as compression, dehydration, etc., by either seller or buyer shall be considered as a change in the existing rate level.

(f) *Notice of change in rate level.* (1) an independent producer who has sold in interstate commerce 5,000,000 Mcf of gas or less annually in each year

*Published in Federal Register on January 10, 1961 (27 F.R. 252).

of his operations during the preceding five years and who is proposing a contractual change in rates, charges, etc., shall file the information called for in the following form:

Notice of Independent Producer Rate Change Filing

1. Producer: _____ (Name)
   _____ (Address)
2. Buyer: _____ (Name)
3. Location of sale: _____ (Field) (County) (State)
4. (a) FPC Gas Rate Schedule No. __; (b) Basis contract date _____
5. (a) Type of increase: _____ (Periodic, favored-nation, renegotiated, etc.)
   (b) Contract basis: _____ (Specify contract provision)
   (c) _____ _____ (Proposed effective date)
6. Rates in cents per Mcf at _____ (Specify) psia:

	Base rate	Tax reimbursement	Other* (specify separately)	Total rate
(a) Present effective rate:				
(b) Proposed rate:				

7. Statement of estimated sales volume and comparative revenues for the twelve-month period succeeding the proposed effective date (shown with volume and rates at the same psia as in Item 6):

Estimated volume (Mcf)	Revenues at present effective rate	Revenues at proposed rate	Difference in revenues

8. Average Btu content per cubic foot of the gas sold during the last twelve-month period: _____; estimated for the succeeding twelve-month period: _____.

_____ (Date) _____ (Signed)

_____ (Title)

*Dehydration, compression, Btu adjustment, etc.

(2) An independent producer who has sold in interstate commerce more than 5,000,000 Mcf of gas annually in any year during the preceding five years and who is proposing a contractual change in rate level to a price below or equal to the applicable area price level for increased rates as set out in the Statement of General Policy No. 61–1, as amended (§ 2.56 of this chapter), shall file the information required in subsection (f) (1) hereof and may, at his option, submit a statement in support of the proposed change but shall, in any event, submit additional information in explanation of any pertinent circumstance not specifically required by the form.

(3) An independent producer who has sold in interstate commerce more than 5,000,000 Mcf of gas annually in any year during the preceding five years and is proposing a contractual change in rate level to a price higher than the applicable area price level for increased rates set out in the Statement of General Policy No. 61–1, as amended (§ 2.56 of this chapter), and any independent producer (regardless of the quantity of annual sales) proposing an ex parte or unilateral rate

change shall file, in addition to the information required by subsection (f)(1) hereof, a full statement in support of the proposed change in rate.

(g) A complete copy of all material filed pursuant to this section shall be furnished to each party to the rate schedule. With each such filing there shall be submitted to the Commission a list of the parties to whom such material has been furnished.

(B) The amendments herein adopted shall become effective February 12, 1962.

(C) The Secretary shall cause prompt publication of this order to be made in the Federal Register.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

MIDWESTERN GAS TRANSMISSION COMPANY, DOCKET NOS. G–18313, G–18314, G–18315; MICHIGAN WISCONSIN PIPE LINE COMPANY, DOCKET NO. G–18316

ORDER EXTENDING TIME

(Issued January 5, 1962)

Our order of October 31, 1959, directed Michigan Wisconsin Pipe Line Company (Mich. Wis.) to deliver and sell natural gas to Michigan Gas and Electric Company (MG & E) at Menominee, Michigan. By ordering paragraphs (Q) and (R) we subjected the direction to Mich. Wis. to certain conditions requiring affirmative actions by MG & E, as to construction of its project, contracting with its principal customer, and securing necessary State authorizations. By order of April 7, 1960, we granted MG & E's motion to stay the deadline for complying with the conditions of paragraphs (Q) and (R). Under our April 7 order, the stay expires 60 days after the Supreme Court's denial of a petition for a writ of certiorari in *Michigan Gas & Electric Co.* v. *F.P.C.*, No. 368 October Term 1961. The Supreme Court denied certiorari on November 6, 1961.

On December 29, 1961, MG & E filed a lengthy motion for reconsideration of the requirements of our order of October 31, 1959, and for extension of time for compliance. It is reasonable that we further extend the time for compliance with the conditions of paragraphs (Q) and (R) in order that we may consider the merits of MG & E's latest motion.

The Commission orders:

The time for compliance by Michigan Gas and Electric Company with ordering paragraphs (Q) and (R) of our order of October 31, 1959, is hereby extended pending further order of the Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TENNECO CORPORATION, DOCKET NOS. CI61–1272, CI61–1273 AND CI61–1475; TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. CP61–264

ORDER DENYING MOTION TO DISMISS AND ORDER REQUIRING THE FILING OF SECTION 7(b) ABANDONMENT APPLICATIONS

(Issued January 5, 1962)

On December 8, 1961, the Commission staff counsel filed a motion to dismiss all of the above applications. The following grounds were advanced as warranting dismissal:

(1) Tennessee Gas Transmission Company (Tennessee) and Tenneco Corporation (Tenneco) failed to present evidence concerning the effect of the transfer of certain gas leases, if permitted, on tax benefits [1] and thus on Tennessee's rates.

(2) Tennessee failed to file applications pursuant to Section 7(b) of the Natural Gas Act to abandon reserves now dedicated to public service.

The motion arises within the framework of proceedings upon applications filed by Tenneco for certificates of public convenience and necessity under Section 7(c) of the Act. The applications were filed in Docket Nos. CI61–1272 and CI61–1273 to assume sales and deliveries of natural gas being made in interstate commerce by its corporate parent Tennessee.[2] The sales to be assumed in the former docket involve Tennessee's gas production delivered into its own pipeline system. In Docket No. CI61–1273, the subject sales are made by Tennessee to non-affiliated pipeline companies under rate schedules filed with the Commission. In the remaining Tenneco application, Docket No. CI61–1475, a certificate is sought to initiate sales to Tennessee. All of the above sales Tenneco seeks to have certificated involve gas production from leases purportedly transferred to it by Tennessee pursuant to an Instrument of Conveyance dated February 28, 1961.

The application filed by Tennessee in Docket No. CP61–264 is for a certificate authorizing the construction and operation of facilities necessary to take gas produced from the leases involved in Docket No. CI61–1475.

We are of the opinion that the first ground is insufficient to support a dismissal. We recognize, of course, that our order of October 9, 1961,[3] directed the applicants to submit information concerning the possible loss of tax benefits and the impact of that loss on Tennessee's rates. Tennessee responded stating that the question of tax benefits is being adjudicated in its recent rate proceeding now pending the presiding examiner's decision.[4] Their counsel has advised that evidence has not been submitted because Tennessee is awaiting decision of this question.

We believe that dismissal is unwarranted at this time because of the necessity of weighing the circumstances of the tax questions along with other factors relevant to a determination whether the transfer would be in the public interest. We stress however, applicant runs the risk of failing to make a record sufficient to enable us to pass upon all relevant considerations.

With respect to the other ground raised by staff counsel concerning Tennessee's failure to file applications for abandonment authorization of the sales and leases involved in Docket Nos. CI61–1272, CI61–1273, and CI61–1475, we are satisfied that the mere absence of filing such applications should not constitute a ground for dismissal. Dismissal without affording further opportunity to correct the deficiency would seem to elevate pleading above substance. However, we believe that such applications are required by the Act.

Accordingly, we shall extend an opportunity to Tennessee to file abandonment applications pursuant to Section 7(b). If such are filed, they will be consolidated for hearing and decision along with the above-entitled Section 7(c) proceedings. This procedure would avoid delay in processing the Section 7(b) applications and provide for simultaneous disposition thereof.

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[1] Tax benefits available to Tennessee by operation of *Internal Revenue Code of 1954*, Sections 611–613 pertaining to percentage depletion deductions, and Section 263(c) which permits deductions with respect to intangible well-drilling and development costs of oil and gas wells.

[2] Tennessee owns all of Tenneco's common stock which carries 75 percent of the voting rights.

[3] "Order Denying Applications for Rehearing, Denying Requests for Temporary Certificates, Requiring the Filing of Information, Consolidated Proceedings, and Fixing Date of Hearing."

[4] Tennessee Gas Transmission Company, Docket No. G–19983.

The Commission finds:

(1) The reasons presented in the motion do not warrant, without consideration of other factors in the proceeding affecting the public interest, dismissal of the applications at this time. Accordingly, the motion to dismiss filed by staff counsel December 8, 1961, should be denied.

(2) The Natural Gas Act, Section 7(b) requires that Tennessee file appropriate applications, pursuant thereto, for permission to abandon the leases from which Tenneco proposes sales and deliveries of gas to Tennessee in Docket No. CI61–1272.

The Commission orders:

(A) The reasons presented in the motion do not warrant, without consideration of other factors in the proceeding affecting the public interest, dismissal of the applications at this time. Accordingly, the motion to dismiss, filed by staff counsel December 8, 1961, is hereby denied.

(B) The Natural Gas Act, Section 7(b) requires that Tennessee file appropriate applications, pursuant thereto, for permission to abandon the leases from which Tenneco proposes sales and deliveries of gas to Tennessee in Docket No. CI61–1272.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

UNITED CARBON COMPANY, DOCKET NO. RI61–269

ORDER DENYING PETITION FOR REHEARING AND RECONSIDERATION

(Issued January 5, 1962)

On December 8, 1961, United Carbon Company (United Carbon) tendered for filing a petition requesting rehearing and reconsideration of the Commission's order issued November 7, 1961, denying United Carbon's petition to terminate the above-entitled proceeding.

In its petition, United Carbon states that other suspension proceedings involving a similar increased rate for the sale of gas to the same buyer from lands in the same area have been terminated, and that United Carbon should be accorded the same treatment. It states that this proceeding is unnecessary in view of the extensive record made in the hearings in Docket Nos. G–9572, *et al.*[1]

United Carbon refers to cost data previously submitted in which it states it applied the same cost-of-service principles as those used in Opinion No. 340, resulting in a unit cost substantially in excess of the proposed increased rate. Further, United Carbon states that production is declining in the area in question, necessitating increased drilling and drilling at greater depths.

The Commission finds:

The petition for rehearing and reconsideration sets forth no new facts and no principles of law which either were not fully considered by the Commission when it adopted the order issued November 7, 1961, or which having been now considered warrant any change in, vacation, or modification of such order.

The Commission orders:

The petition for rehearing and reconsideration filed herein by United Carbon be and it is hereby denied.

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[1] *United Carbon Company, et al.*, Opinion No. 340, Docket Nos. G–9572, *et al.*, January 27, 1961, 25 FPC 181.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

MICHIGAN GAS STORAGE COMPANY, DOCKET NO. CP62-35

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 8, 1962)

On August 14, 1961, as supplemented on September 29, 1961, Michigan Gas Storage Company (Applicant) filed in Docket No. CP62-35 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of certain facilities in order to establish two new delivery points and to enlarge an existing delivery point to enable Applicant to deliver natural gas to Consumers Power Company (Consumers), its affiliate and sole customer. Consumers proposes to utilize said gas to initiate retail natural gas service in the Township of Bath, the Village of Stockbridge and the City of Lake City, located, respectively, in Clinton, Ingham and Missaukee Counties, Michigan.

Applicant proposes to construct and operate the following facilities:

(1) For service to Bath, meter and regulator facilities on Applicant's Lansing pipeline lateral in Victor Township, Clinton County, Michigan, at an estimated cost of $19,000;

(2) For service to Stockbridge, meter and regulator facilities on Applicant's Freedom-Laingsburg pipeline in Unadilla Township, Livingston County, Michigan, at an estimated cost of $18,000; and

(3) For service to Lake City, enlargement of Applicant's existing McBain meter station in Riverside Township, Missaukee County, Michigan, at an estimated cost of $3,000.

The application shows the following estimated natural gas requirements for the three communities:

	Bath	Stockbridge	Lake City
Peak day (Mcf):			
1st year	162	322	452
2d year	177	350	477
3d year	188	384	502
Annual (Mcf):			
1st year	24,890	47,633	69,419
2d year	26,920	51,730	73,299
3d year	28,538	55,827	77,121

The total estimated cost of $40,000 for construction of the proposed facilities will be financed by Applicant from funds on hand.

Consumers will build the distribution facilities necessary to render natural gas service to the three communities.

The proposed sale of natural gas to Consumers will be made pursuant to Applicant's FPC Gas Tariff, Original Volume No. 1, Rate Schedule X-1.

Applicant was granted temporary authorization by letter, dated November 2, 1961.

Pursuant to due notice, a public hearing was held in Washington, D.C., on December 28, 1961, respecting the matters involved in and the issues presented by the application, as supplemented, herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Michigan Gas Storage Company, a Michigan corporation having its principal place of business in Jackson, Michigan, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of December 3, 1946, in Docket No. G–731 (5 FPC 965).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce for resale, subject to the jurisdiction of the Commission and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities and the proposed transportation and sale of natural gas to Consumers for resale, by Applicant, are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the general terms and conditions set forth in paragraphs (b), (c)(1), (c)(3), (c)(4), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.20 should attach to the issuance of the certificate hereinafter granted to Applicant and to the exercise of the rights granted thereunder, and that the construction of the facilities authorized by this order shall be completed and said facilities placed in actual operation within 12 months from the date on which this order issues.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record, and not having been denied by the Commission is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Michigan Gas Storage Company, to construct and operate the proposed facilities and to sell and deliver natural gas to Consumers Power Company, as hereinafter described, all as more fully described in the application, as supplemented, herein, upon the terms and conditions of this order.

(B) The general terms and conditions set forth in paragraphs (b), (c)(1), (c)(3), (c)(4), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act shall attach to the issuance of the certificate granted in paragraph (A) hereof and to the exercise of the rights granted thereunder.

(C) The facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 12 months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP61-132

ORDER REFERRING COMPLAINT TO PRESIDING EXAMINER

(Issued January 8, 1962)

On November 13, 1961, the Commission received a letter dated November 9, 1961, in the nature of a complaint from Mid-America Pipeline Company (Mid-America) charging that Northern Natural Gas Company (Northern), the applicant herein, has, in violation of Section 7(c) of the Natural Gas Act, without a certificate of public convenience and necessity, installed a material part of the facilities for which it seeks authorization in this proceeding.

Mid-America says, among other things, that Northern in this proceeding "specifically sought certificate authorization to install and operate the following facilities (Tr. 87, Exh. 5):

(a) Compressor facilities—$2,804,600 (6,000 hp (3-2000 hp units) at Bushton station).

(b) Connecting facilities—$317,800 (over one mile of connecting 30" and 20" lines).

(c) Measurement facilities—$69,900.

(d) Mainline pipeline improvements—$435,300.

These facilities, with the exception of the mainline improvements are all shown in diagram on page 6 of Northern's Exhibit 7." (D)

Mid-America also says that it has been reliably informed that the above facilities and modifications, or a material part of them, have already been installed without authorization. Specifically:

(a) The connecting lines shown on Exh. 7 are installed and connected to the extraction plant;

(b) The controls and calorimetric equipment has been installed and connected to the system;

(c) One 2,000 hp compressor has apparently been installed, and may be connected to the system, as shown in Exh. 7;

(d) Northern is, or has been, delivering natural gas from its mainline to Northern Gas Products who in turn has been using it to fire the extraction plant boilers, and also to fuel a gas engine driven generator.

(e) The various mainline improvements apparently have been completed; See Tr. 92.

Mid-America says it does not know whether the natural gas liquids extraction plant to be located adjacent to Northern's Bushton Compressor Station has actually been "placed on line" and extraction operations conducted on a test basis, but that it appears that the plant could be operated on a few hours notice.

Mid-America urges the Commission, if it confirms that Northern has violated Section 7(c) of the Act, to direct Northern to show cause why Northern's application herein should not be summarily denied.

The Commission on November 17, 1961, by letter addressed to the president of Northern directed Northern to reply to said complaint of Mid-America.

Northern did by letter dated November 20, 1961, addressed to the Secretary of the Commission, answer said complaint, which answer was filed with the Commission on November 21, 1961.

On November 29, 1961, a letter dated November 27, 1961, was filed by Mid-America responding to Northern's answer of November 20, 1961.

The Commission finds:

It is appropriate to carry out the provisions of the Natural Gas Act, and in the public interest, that the issue raised by the above-described pleadings should be considered by the Presiding Examiner in connection with his disposition of the issues presented by the record made at the hearing on the application herein.

The Commission orders:

The above-described complaint of Mid-America Pipeline Company together with the answer of Northern Natural Gas Company and the response of Mid-America to Northern's answer be and the same are hereby referred to the Presiding Examiner to be considered by him in connection with his disposition of this proceeding.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

THE OHIO FUEL GAS COMPANY, DOCKET NO. CP62-68

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 8, 1962)

On September 18, 1961, The Ohio Fuel Gas Company (Applicant) filed an application in Docket No. CP62-68, pursuant to Section 7(c) of the Natural Gas Act, for a certificate of public convenience and necessity authorizing the construction and operation of certain facilities necessary to render retail natural gas service in the incorporated Village of Cheshire, Gallia County, Ohio, and environs.

Applicant proposes to tap its Line F-258 and to construct and operate 75 feet of 2-inch pipeline at an estimated cost of $450. Applicant states that it will also construct and operate a distribution system within and adjacent to Cheshire at an estimated cost of $40,892.

The estimated requirements for the proposed service to Cheshire are:

	Year		
	1st	2d	3d
Annual, Mcf	17,566	24,142	25,344
Peak day, Mcf	182	230	249

The volumes involved are too small to have any appreciable impact on Applicant's overall gas supply.

The cost of constructing the proposed facilities will be financed from cash on hand.

Pursuant to due notice, a public hearing was held in Washington, D.C., on December 21, 1961, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, The Ohio Fuel Gas Company, an Ohio corporation having its principal place of business in Columbus, Ohio, is a "natural-gas company" within

the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of August 21, 1945, in Docket No. G–371 (4 FPC 1033).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission and the construction and operation thereof by Applicant are subject to the requirements of Subsection (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.20) should attach to the certificate hereinafter issued to Applicant and to the exercise of the rights granted thereunder, and that the construction of the facilities authorized by this order shall be completed and said facilities placed in actual operation within 6 months from the date on which this order issues.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, The Ohio Fuel Gas Company, to construct and operate the proposed facilities and to transport natural gas as hereinbefore described, all as more fully described in the application herein, upon the terms and conditions of this order.

(B) The general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act shall attach to the issuance of the certificate granted in paragraph (A) hereof and to the exercise of the rights granted thereunder.

(C) The facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 6 months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

RIO GRANDE VALLEY GAS COMPANY, DOCKET NOS. G–1368 AND G–1369

ORDER RESCINDING ORDER AND PERMIT

(Issued January 8, 1962)

Rio Grande Valley Gas Company (Rio), a Texas corporation with principal place of business in Brownsville, Texas, was authorized by order of the Commission issued on March 8, 1951, in *Rio Grande Valley Gas Company*, Docket No. G–1368, 10 FPC 807, pursuant to Section 3 of the Natural Gas Act, to export

natural gas from the United States to Mexico under a contract, dated April 1, 1950, with Gas de Matamoros, S.A. (Matamoros) for resale and distribution to domestic, commercial and industrial consumers in the City of Matamoros, Tamaulipas, Mexico and its environs. The City of Matamoros is located on the opposite side of the Rio Grande River across from Brownsville. Rio is also the holder of a Presidential Permit, dated December 20, 1950, for which it made application in Docket No. G–1369 and which was released to it by the aforesaid order in Docket No. G–1368, pursuant to Executive Order No. 8202 of July 13, 1939, to be effective as of February 5, 1951. This Permit granted Rio permission to construct, operate and maintain certain specified natural gas facilities extending from an existing 8-inch pipe line in Brownsville to a point of connection in the Rio Grande River with proposed pipeline facilities of Matamoros at the border of the United States and Mexico and to connect the same to the proposed facilities of Matamoros for the exportation of natural gas to Mexico in accordance with the aforesaid Section 3 authorization.

Executive Order No. 8202 of July 13, 1939 was revoked and superseded by Executive Order No. 10485 of September 3, 1953. Section 4 of the latter Order provides: "All Presidential Permits heretofore issued pursuant to Executive Order No. 8202 of July 13, 1939, and in force at the time of the issuance of this order, and all permits issued hereunder, shall remain in full force and effect until modified or revoked by the President or by the Federal Power Commission". The aforesaid Permit and Section 3 authorization are presently outstanding and in full force and effect.

Rio, by letter in response to communications from the Commission, states that the projected line to Matamoros, Mexico was never installed because of the failure of Gas de Matamoros, S.A. to complete its arrangements, and that the proposal has been abandoned.

The Commission finds:

(1) It is necessary and appropriate to carry out the provisions of the Natural Gas Act that the order of the Commission issued on March 8, 1951, in *Rio Grande Valley Gas Company*, Docket No. G–1368, 10 FPC 807, be rescinded.

(2) The Presidential Permit of December 20, 1950, applied for by Rio Grande Valley Gas Company in Docket No. G–1369 and released by order of the Commission issued in Docket No. G–1368 on March 8, 1951 and which granted executive permission to said company to construct, operate, maintain and connect certain natural gas facilities at the international boundary of the United States and Mexico at or near Brownsville, Texas for the exportation of natural gas from the United States to Mexico, as hereinbefore described, should be rescinded.

The Commission orders:

(A) The order of the Commission heretofore issued on March 8, 1951 in *Rio Grande Valley Gas Company*, Docket No. G–1368, 10 FPC 807, be and the same hereby is rescinded.

(B) The Presidential Permit of December 20, 1950, heretofore released, issued and granted to Rio Grande Valley Gas Company as set forth in Finding (2) hereof, be and the same hereby is rescinded.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. G–17485, ET AL., G–20570, ET AL., CP61–1

ORDER GRANTING PETITION TO AMEND

(Issued January 9, 1962)

On October 27, 1961, Northern Natural Gas Company (Northern), a Delaware corporation with principal place of business at 2223 Dodge Street, Omaha 1, Nebraska, filed in the above-entitled proceedings a "Petition to Amend Orders Granting Certificates of Public Convenience and Necessity". In the order accompanying Opinion No. 324, issued July 31, 1959, in Docket Nos. G–17485, *et al.*, 22 FPC 164, as amended August 26, 1960, 24 FPC 341, and November 1, 1961, 26 FPC 672, Northern was authorized to construct and operate certain facilities so as to sell and deliver gas to distributors desiring to initiate natural-gas service in about 342 communities. In Docket No. CP61–1, by an order issued March 17, 1961, 25 FPC 540, the Commission affirmed with minor modifications the examiner's decision issued February 21, 1961, 25 FPC 542, authorizing Northern to construct and operate the facilities required to sell and deliver gas to a new large industrial customer and to make sales for resale to one privately-owned distributor and one municipally-owned distributor desiring to serve Silver Bay and Two Harbors, Minnesota, respectively. By the order accompanying Opinion No. 345, issued June 28, 1961, in Docket Nos. G–20570, *et al.*, 25 FPC 1234, Northern was authorized to construct and operate facilities to provide for the increased requirements of its existing utility customers and to commence the sale of 75,000 Mcf of gas per day to a new pipeline customer, Michigan Wisconsin Pipe Line Company.

Northern's petition states that when the Commission, by order issued October 5, 1961, in Docket Nos. CP61–190, *et al.*, 26 FPC 557, authorized Northern to supply up to 89,005 Mcf per day of contract demand from the Mt. Simon reservoir of Northern's Redfield, Iowa, underground storage field, certain main-line facilities heretofore authorized, but not yet constructed pursuant to the orders issued in the aforementioned proceedings in Docket Nos. G–17485, *et al.*, Docket Nos. G–20570, *et al.*, and Docket No. CP61–1, were obviated by the certificated increase in storage facilities.

Additionally, it should be noted that in the order issued November 1, 1961, 26 FPC 672, amending the order accompanying Opinion No. 324, Western Power and Gas Company (formerly Central Electric and Gas Company), instead of Central Natural Gas Company, was shown as the distributor to whom Northern is now authorized to sell gas for distribution in the communities of Lonsdale, Morristown, Veseli and Waterville, Minnesota. This order will also correct the order issued November 1, 1961, so as to authorize Northern to sell gas to Central Natural Gas Company for resale in these four Minnesota communities, in lieu of Western Power and Gas Company.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Northern's petition filed October 27, 1961, requesting amendment of three different Commission orders, be granted so as to modify the orders in the following respects:

(1) The order accompanying Opinion No. 324, issued July 31, 1959, 22 FPC 164, 179, as amended August 26, 1960, 24 FPC 341, and November 1, 1961, 26

FPC 672, should be amended to delete therefrom Northern's authorization to construct compressor facilities in the amount of 2000 horsepower at the Ogden Station and 3400 horsepower at the Oakland Station.

(2) The order accompanying Opinion No. 345, issued June 28, 1961, 25 FPC 1234, should be amended to delete therefrom Northern's authorization to construct compressor facilities in the amount of 2000 horsepower at the Palmyra Station, 4000 horsepower at the Beatrice Station, 2000 horsepower at the Bushton Station, and 2000 horsepower at the Mullinville Station, as well as the following 30-inch main-line loops: 17.9 miles north of Oakland, Iowa, 15.4 miles northeast of Palmyra, Nebraska, 10.8 miles north of Clifton, Kansas, 11.7 miles north of Tescott, Kansas, 9.8 miles north of Bushton, Kansas, and 8.6 miles north of Macksville, Kansas.

(3) The order issued March 17, 1961, 25 FPC 542, affirming with minor modifications the examiner's decision in Docket No. CP61–1 should be amended to delete therefrom Northern's authorization to construct 6.4 miles of 30-inch main-line loop north of Bushton, Kansas.[1]

The Commission orders:

(A) Paragraph (A) of the Commission's order accompanying Opinion No. 324, issued July 31, 1959, 22 FPC 164, 179, as amended August 26, 1960, 24 FPC 341, and November 1, 1961, 26 FPC 672, is hereby further amended so as to delete therefrom Northern's authorization to construct the facilities hereinbefore described in paragraph (1) and the footnote pertaining to paragraph (3) as requested by Northern in its petition to amend filed October 27, 1961.

(B) Paragraph (A) of the Commission's order accompanying Opinion No. 345, issued June 28, 1961, 25 FPC 1234, is hereby amended so as to delete therefrom Northern's authorization to construct the facilities hereinbefore described in paragraph (2), as requested by Northern in its petition to amend filed October 27, 1961.

(C) Paragraph (B) of the Commission's order issued March 17, 1961, 25 FPC 541, affirming with minor modifications the examiner's decision issued February 21, 1961, in Docket No. CP61–1, is hereby amended so as to delete therefrom Northern's authorization to construct the facilities hereinbefore described in paragraph (3), as requested by Northern in its petition to amend filed October 27, 1961.[2]

(D) The Commission's order issued November 1, 1961, 26 FPC 672, amending the order accompanying Opinion No. 324, is hereby corrected so as to indicate on page 4 thereof that Central Natural Gas Company, rather than Western Power and Gas Company, is the present distributor to whom Northern is authorized to sell and deliver gas for resale in the four Minnesota communities of Lonsdale, Morristown, Veseli, and Waterville.

(E) All other provisions of the order accompanying Opinion No. 324, 22 FPC 179, as amended August 26, 1960, 24 FPC 341 and November 1, 1961, 26 FPC 672, of the order issued June 28, 1961, accompanying Opinion No. 345, 25 FPC 1234, and of the order issued March 17, 1961, 25 FPC 540, affirming with minor modifications the examiner's decision in Docket No. CP61–1, shall remain unchanged.

[1] The order issued August 26, 1960, 24 FPC 341, amending the order accompanying Opinion No. 324, had conditioned Northern's authorization to construct this same loop upon the final disposition of Northern's application in Docket No. CP61–1 which was then pending before the Commission. The amendment herein should be construed as deletion of Northern's authorization to construct this particular segment of main-line loop regardless of whether the authorization may be considered to have been established by the order accompanying Opinion No. 324 or by the order affirming the examiner's decision in Docket No. CP61–1.

[2] Northern estimates the cost of all the facilities, for which construction authorization is herein deleted, to be $13,174,400, including interest and overheads.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TEXACO-SEABOARD, INC., ET AL.[1] DOCKET NO. G-13169, ET AL.;
TEXAS GAS EXPLORATION CO., ET AL.[1] DOCKET NO. G-17336, ET AL.;
REPUBLIC NATURAL GAS CO., ET AL.[1] DOCKET NO. G-16540, ET AL.

ORDER DENYING MOTIONS DISMISSING PETITION AND ISSUING NOTICE OF REFUND OBLIGATIONS

(Issued January 10, 1962)*

In each of the above-captioned dockets we have heretofore issued unconditional permanent certificates of public convenience and necessity under Section 7(c) of the Natural Gas Act. These certificates are still outstanding, but the proceedings are before us again as a result either of judicial remand or our own grant of rehearing, for the purpose of reconsideration, upon applications therefor duly filed under Section 19(a) of the Act. Each of these proceedings is consolidated for hearing with Docket No. AR61-2.

These dockets fall into three groups:

I. Sales to Transcontinental Gas Pipe Line Corporation (Transco); certificates issued by order accompanying Opinion 315, 20 FPC 264. This order was affirmed by the United States Court of Appeals, for the Third Circuit, *United Gas Improvement Co.* v. *F.P.C.*, 269 F. 2d 865, but remanded by the Supreme Court, *Public Service Commission of New York* v. *F.P.C.*, 361 U.S. 195, with instructions to reconsider and redetermine in the light of *Catco* (*Atlantic Refining Co.* v. *Public Service Commission of New York*, 360 U.S. 378).

II. Sales to Hope Natural Gas Company; certificates issued by order accompanying Opinion 327, 22 FPC 378. This order was "reversed" on appeal "insofar as it grants unconditional certification to the initial price proposals". *Public Service Commission of New York* v. *F.P.C.*, 287 F. 2d 146 (CADC), cert. denied *sub nom.*, *Hope Natural Gas Co.* v. *Public Service Commission of New York*, 365 U.S. 880.

III. Sales to Transco; certificates issued by order of November 17, 1959, 22 FPC 836. We granted rehearing (as to dockets listed in Appendix II only) by order of January 15, 1960, in Docket Nos. G-16603 *et al.* (unreported).

When we first consolidated these various proceedings for hearing with Docket No. AR61-2, we contemplated an early decision on the initial rates proposed in these and other dockets. We have since concluded that such a "two-phase" area proceeding is not feasible at this time and have eliminated the separate "certificate" phase of that proceeding by our order of November 9, 1961. Accordingly, we deem it incumbent upon us once more to consider these proceedings and to determine what further remedies, if any, the public interest necessitates.

It is fundamental in a producer certificate proceeding that the applicant show his proposed price "to be in the public interest." *Catco*, 360 U.S. at 390. Certain minimal standards as to price must be met at the outset. The development of these minimal standards has been a continuing process. We reviewed this development in *Socony Mobil Oil Company, Inc.*, Docket No. G-13780, order issued September 25, 1961 (26 FPC 532):

> * * * Traditionally, we have regarded the test as one that relates the proposed price to the previous price structure in the area. See *Cities Serv-*

[1] See Appendices I, II, and III for complete listing of docket numbers and proceedings.
*Order denying rehearing issued March 7, 1962, 27 FPC 482.

ice Gas Co., 14 FPC 134, affirmed sub nom. *Signal Oil and Gas Co.* v. *F.P.C.*, 238 F. 2d 711 (CA3), cert. den., 353 U.S. 923. Immediately after the Supreme Court's *Catco* decision we announced a test of comparison with the highest price in the area previously certificated by us; but that standard was judicially upset for failure to show "a real administrative effort to hold back prices." *Texas Gas Transmission Corp.*, 22 FPC, 378, 388, order set aside sub nom. *P.S.C.* of N.Y. v. *F.P.C.*, 287 F. 2d 146, 150 (CADC) cert. den., 365 U.S. 880, 882. * * * .

More recently, on October 31, 1961, we issued our Fourth Amendment to our Statement of General Policy No. 61–1 in which, guided by recent court decisions therein cited, and after careful re-examination of the factors set forth in our original Policy Statement 61–1, we lowered the ceiling for initial prices in Southern Louisiana to 21.25¢ per Mcf inclusive of State taxes and 19.5¢ per Mcf for off-shore sales not subject to the taxing jurisdiction of the State. By this statement we confirm for the future what the courts have held in the past: that initial prices at the levels proposed herein are out of line and cannot be approved unless justified by compelling evidence after full hearing; such evidence has not been adduced to date.

While we have power to redetermine these proceedings on the basis of the respective records as originally made and in the light of additional facts of which we may take official notice, we adhere to the view that it would be fairer and wiser in the present circumstances to offer the applicants a further opportunity to adduce evidence in Docket Nos. AR61–2 *et al.* in support of their proposed prices. But the necessary deferral of final resolution of these proceedings requires us to make it explicit that the public will not be without interim protection.

We have concluded, as to all rates collected by the applicants for the sales involved in these proceedings, that we should explicity impose upon each applicant, to the extent that we are empowered to do so, an obligation to refund any amounts collected in excess of the amounts which would have been collected under the rate or rates finally determined in these proceedings to accord with the requirements of the public convenience and necessity.

We find ample authority under Sections 7, 16, and 19 of the Act so to protect the public interest, pending final disposition of the initial price questions herein. The producer-applicants have no vested rights to receive the benefits of an order issued by the Commission once such order has been remanded to the Commission because its findings could not be supported under existing law. *Securities and Exchange Commission* v. *Chenery Corporation*, et al., 332 U.S. 194; *Federal Communications Commission* v. *Pottsville Broadcasting Company*, 309 U.S. 134, 145. Similarly, applicants have no vested rights under an order as to which we have granted the statutory rehearing.

Recently, in *Socony Mobil Oil Company, Inc.*, Docket No. G–13780, when confronted with the same problem as is presented here, we set aside the permanent certificate and issued temporary authority properly conditioned. But upon further study of this problem, and particularly of the mandate of the District of Columbia Circuit covering Group II of these proceedings, we are now convinced that we can adequately protect the public by redetermining the price issue in the light of governing legal standards. This makes it unnecessary to set aside the certificates.

On June 13, 1960, Transco, the purchaser in the Group I proceedings filed as to those dockets a motion requesting that we reaffirm our order issuing unconditional certificates. However, in view of our findings as to the insufficiency of the evidence heretofore adduced, this motion must be denied insofar

as it requests that we reaffirm our former approval of the proposed initial prices.

The Public Service Commission of New York (P.S.C.), on June 22, 1961, filed a motion addressed to all the instant proceedings [2] requesting, "* * * orders complying with judicial mandates or requiring the posting of bond or filing of undertakings to assure refunds of any amounts of initial rates herein found unlawful." A similar motion, requesting the Commission to provide interim consumer protection in compliance with judicial mandates was filed by the Long Island Lighting Company, Philadelphia Electric Company, Public Service Electric and Gas Company and The United Gas Improvement Company (Joint Movants), on July 10, 1961.[3] The order issued herein will clarify the Commission's position in regard to refund obligations, but deny the relief sought by these motions, insofar as they request the posting of bond to assure refunds. We note that the cost of bonding, if the bonds were to provide adequate coverage, would be excessive and we do not believe that bonds are required to protect the public interest.

Hope Natural Gas Company, purchaser in the Group II proceedings, filed a petition for declaratory order under Section 1.7(c) of the Commission's Rules of Practice and Procedure on August 16, 1961, requesting that the Commission either affirm the propriety of Hope's continuing to pay the contract prices which are the subject of those proceedings or take such further action as the Commission may deem appropriate under the circumstances. Neither P.S.C. nor Joint Movants have challenged the propriety of Hope's continuing to make payments in accordance with the contract rates filed by the producers. Neither P.S.C. nor Joint Movants answered Hope's petition; but several producers have done so and pointed out that they agreed with Hope's position that it should pay the filed rates until such time as those rates are adjusted. These answers correctly observe that Hope fails to demonstrate the existence of any controversy or uncertainty which calls for issuance of a declaratory order under our Rules. Accordingly, Hope's petition should be dismissed.

The Commission orders:

(A) The amounts collected by the applicants listed in Appendices I, II and III (or by their predecessors or successors in interest) under the rate schedules covering the sales involved in the listed proceedings shall be subject to such refund provisions as the Commission may lawfully perscribe by its final order in these proceedings (all of which have been consolidated with Docket No. AR61-2) to the extent, if any, that the rate which has been collected exceeds the rate ultimately found to accord with the requirements of the public convenience and necessity.

(B) Except as hereinabove granted, the motions of Transcontinental Gas Pipe Line Corporation, filed June 13, 1960, of the Public Service Commission of New York, filed June 22, 1961, and of Long Island Lighting Company, Philadelphia Electric Company, Public Service Electric and Gas Company and The United Gas Improvement Company, filed July 10, 1961, are denied insofar as they relate to the dockets listed in Appendices I, II and III.

(C) The petition of the Hope Natural Gas Company, filed on August 16, 1961, is dismissed.

(D) The Secretary of the Commission is hereby directed to file a copy of this order as a part of each of the rate schedules listed in Appendices I, II and III, as

[2] Except Docket No. G-17447. P.S.C.'s motion also speaks to several proceedings not covered by this order.

[3] Joint Movants address their motion to the Group I and III dockets (except Docket Nos. G-13293, G-13746, G-14244 and G-17447) as well as other proceedings not covered by this order.

well as any rate schedules which may hereafter be filed in connection with the sales proposed in Docket Nos. G–14355 and G–17341.

APPENDIX I

Sales to Transcontinental Gas Pipe Line Corporation (Transco); certificates issued by Opinion 315, 20 FPC 264;[1] *remanded, see 361 U.S. 195*

Docket No.	Seller	Rate schedule No.	Total price ¢/Mcf @ 15.025 psia
G–13169	Texaco-Seaboard Inc.	26	23.30
G–13183	Placid Oil Company, Operator *et al*	19	23.55
G–13184	Placid Oil Company	18	23.55
G–13197	Frankel, J. R. *et al*	2	23.55
G–13219	Atlantic Refining Company	189	23.30
G–13231	Pan American Petroleum Corporation	206	23.55
G–13232	Pan American Petroleum Corporation	205	23.55
G–13233	Pan American Petroleum Corporation, Operator *et al*	204	23.55
G–13293	The California Company, a division of California Oil Company	12	22.8
G–13356	Amerada Petroleum Corporation	63	23.55
G–13642	Republic Natural Gas Company, Operator *et al*	[2] 21	23.55
G–13710	Sun Oil Company	92	23.55
G–13746	Socony-Mobil Oil Company, Inc.	176	22.2625
G–13757	Newmont Oil Company	3	22.2625
G–13758	Continental Oil Company	158	22.2625
G–13973	Sohio Petroleum Company	48	23.55
G–14109	Hassie Hunt Trust, Operator *et al*	19	23.55
G–14164	Austral Oil Company, Inc., Operator Agent for Oil Participations Inc.	[3] 10	23.55
G–14203	Union Oil Company of California	26	22.15
G–14227	Union Texas Natural Gas Corporation [4]	9	23.05
G–14240	Diversa Inc	[5] 3	23.3
G–14242	Austral Oil Company, Inc., Operator Agent for Oil Participations Inc.	[6] 12	23.55
G–14243	Austral Oil Company, Inc., Operator Agent for Oil Participations Inc.	[7] 11	23.55
G–14244	Phillips Petroleum Company	350	22.2625
G–14254	Sun Oil Company	101	21.40
G–14256	Humble Oil and Refining Company, Operator *et al*	[8] 263	23.05
G–14346	The Ohio Oil Company	42	21.40
G–14351	The Pure Oil Company	39	21.40
G–14355	Cities Service Production Company	[9]	
G–14356	Cities Service Production Company	9	23.55
G–14362	Union Oil Company of California	25	23.55
G–14385	Tidewater Oil Company	80	23.55
G–14604	Humble Oil and Refining Company	131	23.55
G–14605	Humble Oil and Refining Company	129	23.55
G–14606	Humble Oil and Refining Company	128	23.55
G–14607	Humble Oil and Refining Company	130	23.55

[1] The certificate issued in Docket No. G–13218 was vacated, and Lone Star Producing Company was permitted to withdraw its Rate Schedule No. 62 by our order of December 1, 1961.
[2] Interests of Texaco Inc., added temporary authorization issued June 30, 1959, in certificate Docket No. G–18344.
[3] Formerly Oil Participations Inc., Rate Schedule No. 9.
[4] Formerly Union Oil and Gas Corporation of Louisiana, Rate Schedule No. 9.
[5] Formerly C. G. Glasscock-Tidelands Oil Co., Rate Schedule No. 3.
[6] Formerly Oil Participations, Inc., Rate Schedule No. 11.
[7] Formerly Oil Participations, Inc., Rate Schedule No. 10.
[8] Formerly Monterey Oil Company Rate Schedule No. 13. This rate schedule is in a Section 4(e) proceeding, Docket No. G–17663.
[9] No rate schedule filed. Sales made pursuant to Austral Oil Company, Inc., Operator, Rate Schedule No. 12.

APPENDIX II

Sales to Hope Natural Gas Company; certificates issued by Opinion 327, 22 FPC 378; remanded, see 287 F. 2d 146 (CADC)

Docket No.	Seller	Rate schedule No.	Total price ¢/Mcf @ 15.025 psia
G-17336	Texas Gas Exploration Corporation, Operator *et al*	3	23.55
G-17337	J. Ray McDermott and Company, Inc	12	23.55
G-17338	Kilroy Properties, Inc. *et al*	3	23.55
G-17339	The California Company, a division of California Oil Company, Operator *et al*	14	23.55
G-17340	Gallery Properties, Inc	2	23.55
G-17341	Gallery Properties, Inc	(1)	
G-17342	Ocean Drilling and Exploration Company	1	23.55
G-17343	Ocean Drilling and Exploration Company, Operator *et al*	2	23.55
G-17391	Humble Oil and Refining Company	167	23.55
G-17393	Amerada Petroleum Corporation	85	23.55
G-17396	Kerr-McGee Oil Industries Inc	64	23.55
G-17397	Bel Oil Corporation	7	23.55
G-17398	Sands, Caroline Hunt *et al*	5	23.55
G-17399	Sid W. Richardson d/b/a Richardson & Bass, Operator *et al*	2	23.05
G-17401	Socony-Mobil Oil Company, Inc	203	23.55
G-17402	Beck Oil Company	[2] 2	23.55
G-17405	Phillips Petroleum Company *et al*	355	23.55
G-17407	Amerada Petroleum Corporation	84	23.05
G-17413	Mississippi River Fuel Corporation	14	23.55
G-17457	Union Oil Company of California	38	23.55
G-17463	Tidewater Oil Company	92	23.55
G-17474	Tidewater Oil Company	91	23.55
G-17475	Tidewater Oil Company	89	23.55
G-17483	Tidewater Oil Company	90	23.05
G-17554	Continental Oil Company	174	23.55
G-17560	Shell Oil Company	215	23.55
G-17566	Continental Oil Company	171	23.55
G-17574	Pan American Petroleum Corporation	266	23.05

[1] No rate schedule filed. Sales not initiated.
[2] Tentative; this rate schedule has not yet been accepted for filing.

APPENDIX III

Sales to Transco: certificates issued by order of November 17, 1959, 22 FPC 836, rehearing granted as to the following dockets only by unreported order of January 15, 1960, in docket numbers G-16603 et al

Docket No.	Seller	Rate Schedule No.	Total price ¢/Mcf @15.025 psia
G-16540	Republic Natural Gas Company *et al*	23	23.55
G-17381	Kerr-McGee Oil Industries, Inc	69	22.2625
G-17417	Pan American Petroleum Corporation	[1] 312	22.2625
G-17444	Southern Natural Gas Company-Phillips Petroleum Company, Joint Venture	1	22.2625
G-17447	Phillips Petroleum Company	[1] 342	22.2625

[1] Tentative; this rate schedule has not yet been accepted for filing.

THE ARMY LIBRARY
Washington, D.C.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

AREA RATE PROCEEDING, DOCKET NO. AR61-1; CLAUDE E. AIKMAN, ET AL., DOCKET NO. G-18466, ET AL.; NORTH CENTRAL OIL CORPORATION (OPERATOR), ET AL, DOCKET NO. CI60-435, ET AL.

ORDER REQUIRING THAT CERTAIN DATA BE FILED

(Issued January 11, 1962)

By order of August 2, 1961, we required the filing of certain cost data, in accordance with Appendix B to that order,[1] by those respondents whose company-wide jurisdictional sales in 1960 exceeded 2,000,000 Mcf. At that time we announced that we would subsequently issue a further order requiring the furnishing of cost data by the smaller respondents whose company-wide jurisdictional sales during 1960 amounted to 2,000,000 Mcf or less. By order issued herein on December 21, 1961, we revised the volumetric cut-off from 2,000,000 Mcf to 10,000,000 Mcf.

On October 6, 1961, our staff circulated for comment by interested parties a proposed draft "Appendix C" designed to obtain cost data from the smaller respondents. A number of interested parties cooperated in presenting constructive suggestions regarding the draft "Appendix C" and such suggestions were discussed by the parties and our staff at an informal conference on December 5, 1961. We are now prescribing a "small producer" cost data form which we shall denominate Appendix C to this order.* In general, this Appendix requires the reporting of data basically as they are recorded in the respondent's accounts. For those respondents who have expensed the Intangible Development Cost (IDC) of their producing properties, Appendix C offers a simplified method for reporting such costs as part of the investment in the completed well.

We are also convinced that we may reasonably reduce the requirements for reporting of cost data by non-operators; accordingly we shall require reporting of cost data on Appendix B or C as follows:

(1) We shall continue to require the reporting of cost data on Appendix B by all producers whose company-wide jurisdictional sales in 1960 exceeded 10,000,000 Mcf.

(2) We shall generally require those respondents whose company-wide jurisdictional sales in 1960 amounted to 10,000,000 Mcf or less to file either Appendix B or Appendix C, as they select. However, such respondents need not file either Appendix B or Appendix C, provided:

(a) They do not *operate* any property, *in the Permian Basin area*,[2] from which gas is produced and sold subject to the jurisdiction of the Commission; and

(b) The *operator* of any such properties in which they own interest is filing his own (i.e., the operator's) cost data for such properties on either Appendix B or C.

By this action we expect to secure the minimal cost data from the smaller respondents without imposing undue burden. At the same time we will not deny any producer the option of reporting his cost data in full.

(3) Copies of such cost data filings need not be served on any party to these proceeding.

[1] Appendix B was revised by order of September 18, 1961, herein.

[2] Texas Railroad Commission Districts No. 7-C and 8, and Lea, Chaves and Eddy Counties, New Mexico.

*Omitted in printing.

The Commission finds:

It is necessary and appropriate in the public interest and to aid in the enforcement of the Natural Gas Act that respondents herein be required to furnish certain cost data to the Commission as hereinafter ordered.

The Commission orders:

(A) All respondents to these consolidated proceedings, who made company-wide jurisdictional sales of 10,000,000 Mcf or less of natural gas during the year 1960, shall complete and on or before March 26, 1962, shall file with the Secretary of the Commission, three copies of either:

(1) The data required by Appendix B to our order of August 2, 1961 (as revised by our order of September 18, 1961) entitled "Costs and Statistics Pertaining to Oil and Gas Production, Exploration, Gas Gathering and Products Extraction Operations, Year 1960"; or

(2) The data required by Appendix C, prescribed by this order and entitled "Costs and Statistics Pertaining to Oil and Gas Production and Exploration—Small Producers, Year 1960";

Provided, however, That any respondent who made company-wide jurisdictional sales of 10,000,000 Mcf or less of natural gas during the year 1960 need not file either Appendix B or Appendix C if:

(1) Such respondent was not, during 1960, the operator of any leasehold, in the Permian Basin area, from which gas was produced and sold subject to the jurisdiction of the Commission; *and*

(2) The operator of any such leasehold in which such respondent owns an interest is filing his own (i.e., the operator's) cost data for such properties under either Appendix B or Appendix C.

Any respondent excused by the above *proviso* may nonetheless file his cost data in accordance with either Appendix B or C if he elects to do so.

(B) Except as hereinabove, modified the Commission's orders in these proceedings shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

COLORADO INTERSTATE GAS COMPANY, DOCKET NO. CP62-99

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 11, 1962)

On October 19, 1961, Colorado Interstate Gas Company (Applicant) filed in Docket No. CP62-99 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the calendar year 1962 at a total cost not to exceed $800,000, with no single project to exceed a cost of $250,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

Applicant proposes to finance the subject facilities from current working funds.

Pursuant to due notice a public hearing was held in Washington, D.C., on December 27, 1961, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Colorado Interstate Gas Company, a Delaware corporation having its principal place of business in Colorado Springs, Colorado, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of June 9, 1945, in Docket No. G–294 (4 FPC 936).

(2) The facilities hereinbefore decribed, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing pipeline system, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas purchased from producers thereof during the calendar year 1962 as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached (c) a description of the project or projects that have been constructed pursuant to the authorization granted hereunder, (d) the location of said project or projects, (e) the cost of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(6) The authorization granted herein should be limited to construction during the calendar year 1962, and the total cost for facilities to be constructed hereunder be limited to $800,000, with no single project to exceed a cost of $250,000.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Colorado Interstate Gas Company to construct during the calendar year 1962 the proposed facilities hereinbefore described (more fully described in the application filed in this proceeding) and to operate such facilities only to take natural

gas supplies from producers who have received authorization from the Commission to sell natural gas to Colorado Interstate Gas Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) Applicant shall submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the cost of the facilities so constructed, and (f) the names of the independent producers involved together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed hereunder are hereby limited to $800,000, with no single project to exceed a cost of $250,000.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

COLUMBIA GULF TRANSMISSION COMPANY, DOCKET NO. CP62-109

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 11, 1962)

On October 30, 1961, Columbia Gulf Transmission Company (Applicant) filed in Docket No. CP62-109 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the calendar year 1962 at a total cost not to exceed $500,000 with no single project to exceed a cost of $250,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

The subject facilities will be financed from funds on hand.

Pursuant to due notice, a public hearing was held in Washington, D.C., on December 27, 1961, respecting the matters involved in and the issues presented by the application in this proceeding. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Columbia Gulf Transmission Company, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of November 5, 1958, in Docket No. G-15524 (20 FPC 681).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing pipeline system, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas purchased from producers thereof during the calendar year 1962 as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(6) The authorization granted herein should be limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed hereunder should be limited to $500,000, with no single project to exceed a cost of $250,000.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Columbia Gulf Transmission Company to construct during the calendar year 1962 the proposed facilities hereinbefore described (more fully described in the application filed in this proceeding) and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Columbia Gulf Transmission Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(C) Applicant shall submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the costs of the facilities so

constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed hereunder are hereby limited to $500,000, with no single project to exceed a cost of $250,000.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

JAKE L. HAMON, DOCKET NO. G-19257

ORDER ACCEPTING OFFER OF SETTLEMENT AND TERMINATING PROCEEDING

(Issued January 11, 1962)

On August 3, 1959, Jake L. Hamon (Hamon) tendered for filing a proposed increase in rate from 12.12268¢ to 15.0952¢ per Mcf for the jurisdictional sale of natural gas to Tennessee Gas Transmission Company (Tennessee Gas), from Starr County, Texas. By order issued August 26, 1959, the proposed increased rate, designated Supplement No. 1 to Hamon's FPC Gas Rate Schedule No. 12, was suspended until April 1, 1960, when upon proper motion, it became effective subject to a corporate surety bond to assure refund of excess charges found not to be justified.

Hamon, on October 6, 1959, filed a motion requesting the Commission to reconsider its order suspending the proposed increased rate and in support of such motion Hamon submitted cost data. Thereafter, the Commission by letter denied Hamon's motion for reconsideration because the cost data furnished by him were not considered adequate for substantiating the reasonableness of the proposed rate.

On December 14, 1961, Hamon submitted in this proceeding an Offer of Settlement pursuant to Section 1.18(e) of the Commission's Rules of Practice and Procedure and consistent with the provisions of the Second Amendment to the Commission's Statement of General Policy No. 61-1.

In its Offer of Settlement, Hamon proposes that the rate of 14.6¢ per Mcf at 14.65 psia be filed in substitution for the increased rate of 15.0952¢ per Mcf rate to be effective from April 1, 1960 to November 1, 1964.

Under the terms of the Offer of Settlement, the favored-nations and price redetermination clauses would be eliminated from Hamon's contract and a revised schedule providing for a 1.0¢ per Mcf escalation on November 1, 1964 and November 1, 1969, would be substituted therefor.

Tennessee Gas has joined in the Offer of Settlement and approves the proposed contract amendment. No objections to the proposed settlement have been received in this proceeding.

Since the proposed rate of 14.6 cents per Mcf at 14.65 psia is acceptable under the provisions of the Second Amendment to the Commission's Statement of General Policy No. 61-1 [18 CFR, Chapter I, Part 2, Section 2.56] issued December 20, 1960, for jurisdictional sales of natural gas for Texas Railroad Commission District No. 4, it appears that the public interest will best be served by accepting Hamon's proposed settlement as herein provided.

However, we desire to make it clear that acceptance of this Offer of Settlement shall not be construed as approval of any future increased rates proposed by Hamon under the periodic escalation provisions or otherwise.

The Commission finds:

The proposed settlement of this rate proceeding on the basis described herein, as more fully set forth in the Offer of Settlement filed by Hamon with the Commission on December 14, 1961, is in the public interest and appropriate to carry out the provisions of the Natural Gas Act and should be approved by the Commission and made effective as hereinafter ordered.

The Commission orders:

(A) The Offer of Settlement filed by Hamon with the Commission on December 14, 1961, in Docket No. G–19257, is hereby approved in accordance with the provisions of this order.

(B) Within 30 days from the date of issuance of this order, Hamon shall file, subject to approval of the Commission, a supplement to the subject rate schedule reflecting the provisions of the settlement offer herein approved, and shall refund to Tennessee Gas, with interest at the rate of 7 percent per annum to date of refund, all amounts collected for gas sold on and after April 1, 1960, in excess of the settlement rate of 14.6¢ per Mcf. Within 45 days from the date of issuance of this order Hamon shall report to the Commission, in writing and under oath, the amount of refunds paid to Tennessee Gas, showing the calculation thereof including the separate amounts of principal and interest; and Hamon shall file an acknowledgement signed by a responsible officer of Tennessee Gas that said amounts satisfy the obligations under the settlement offer.

(C) Upon full compliance by Hamon with all the terms and conditions of this order this proceeding shall be terminated.

(D) The acceptance of this Offer of Settlement is without prejudice to any findings or determinations that may be made in any proceeding now pending or hereafter instituted by or against Hamon.

LETTER-ORDER DENYING REHEARING

JANUARY 11, 1962.

PAN AMERICAN PETROLEUM CORPORATION,
P.O. Box 591,
Tulsa 2, Oklahoma.

(Attention: Mr. William H. Emerson.)

GENTLEMEN: Your petition for rehearing of the Commission's letter order of November 16, 1961, accepting Supplement No. 3 to your FPC Gas Rate Schedule No. 166 for filing is hereby denied.

Your petition specifically requests removal of the following proviso at the bottom of such letter:

"Further, in the event that any of the documents comprising listed rate schedules and supplements was executed on or after April 3, 1961 and contains provisions, either therein or by adoption of the terms and provisions of other agreements, for a change in rate other than those permitted by Section 154.93 of the Commission's Regulations, such rate provisions shall be inoperative and of no effect at law and any tendered rate change under such provisions will be rejected."

Upon review of the facts of this case, the Commission adheres to its letter order of November 16, 1961. We note, additionally, that Pan American is not injured inasmuch as it has not tendered a rate change proposing to make effective the flexible pricing provisions contained in Article V(2) of its contract of July 27, 1956 with Mountain Fuel Supply Company, as amended.

By direction of the Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. CP62-92

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 11, 1962)

On October 12, 1961, Tennessee Gas Transmission Company (Applicant) filed in Docket No. CP62-92 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the calendar year 1962 at a total cost not to exceed $5,000,000, with no single project to exceed a cost of $500,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

The proposed facilities will be financed from general funds or from revolving credit.

Pursuant to due notice, a public hearing was held in Washington, D.C., on December 27, 1961, respecting the matters involved in and the issues presented by the application in this proceeding. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Tennessee Gas Transmission Company, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order issued July 15, 1947, in Docket No. G-910 (6 FPC 777).

(2) The facilities hereinbefore described, as more fully described in the application herein, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing pipeline system, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of facilities to take natural gas purchased from producers thereof during the calendar year 1962 as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects

that have been constructed pursuant to the authorization granted hereunder, (d) the location of said project or projects, (e) the costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(6) The authorization granted herein should be limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed hereunder should be limited to $5,000,000, with no single project to exceed a cost of $500,000.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Tennessee Gas Transmission Company to construct during the calendar year 1962 the proposed facilities hereinbefore described (more fully described in the application filed in this proceeding) and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Tennessee Gas Transmission Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) Applicant shall submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed hereunder are hereby limited to $5,000,000, with no single project to exceed a cost of $500,000.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

AMERICAN LOUISIANA PIPE LINE COMPANY, DOCKET NO. G–18419; MICHIGAN WISCONSIN PIPE LINE COMPANY, DOCKET NOS. G–12292, G–17512, AND RP60–9.

ORDER REJECTING PROPOSED SETTLEMENT AGREEMENT, REMANDING PROCEEDINGS AND GRANTING SUBPOENA DUCES TECUM

(Issued January 12, 1962)

These proceedings relate to proposed increased rates filed by American Louisiana Pipe Line Company (American Louisiana) and Michigan Wisconsin Pipe Line Company (Michigan Wisconsin). The hearings, which commenced on September 21, 1961, were recessed for the purpose of holding conferences, looking towards limitation and settlement of issues. On September 29, 1961, the Presiding Examiner certified to the Commission the stipulation which resulted from said conferences, and on October 20, 1961, we issued an order stating that the stipulation appeared to be reasonable and setting forth our findings and conclusions regarding certain reservations of the parties with respect to said stipulation.

Subsequent hearings and further conferences resulted in two additional stipulations. On December 11 and 12, 1961, the Presiding Examiner certified, respectively, the aforementioned two supplemental stipulations and the record in these consolidated proceedings for our consideration and resolution. At the same time, the Presiding Examiner transmitted to us the briefs and memoranda of the parties. The record reveals that the parties are not in full agreement on the issues (primarily rate design) sought to be covered by the supplemental stipulations. In view of the lack of agreement by all parties concerned, we conclude that we must reject the supplemental stipulations and that the issues involved must be determined in ordinary course.

To this end, we shall remand these matters to the Presiding Examiner, who may reconvene the hearings for the taking of additional evidence, if he deems such to be necessary, on the issues of rate form and rate level and such other issues as to which the parties have not already concluded their presentations. All parties who have reserved the right of cross-examination pending our action on the two supplemental stipulations shall be extended an opportunity to exercise such rights.

Pursuant to Section 14(c) of the Natural Gas Act and Section 1.23 of the Rules of Practice and Procedure, Michigan Gas and Electric Company (Michigan Gas), on November 28, 1961, filed an application for a *subpoena duces tecum* which would require that Michigan Wisconsin produce certain data and material. The basis of the application is that Michigan Gas desires to show that Michigan Wisconsin should be required to set forth in its tariff the terms and conditions under which Michigan Wisconsin will provide new or additional service from branch or lateral lines. The Commission believes that Michigan Gas should be afforded this opportunity, and that the requested data, which is peculiarly within the knowledge of Michigan Wisconsin, is relevant to that issue. The subpoena is accordingly granted as hereinafter set out.

It is our view that the testimony and evidence with respect to the terms and conditions of providing service from branch or lateral lines is separable from the other issues covered by the supplemental stipulations, and that these matters may be heard and decided in two phases: (1) Issues relating to rate level and rate form of American Louisiana and Michigan Wisconsin; (2) Michigan

Wisconsin's branch or lateral line formula. It would appear appropriate, in order to expedite the case, that the former issues be resolved without awaiting development of the testimony and evidence with respect to the branch line formula.

The Commission finds:

(1) That all parties to these proceedings have not agreed to the First and Second Supplemental Stipulations, and it is necessary, therefore, that the settlement proposed thereby be rejected and these matters be remanded to the Presiding Examiner for further proceedings as hereinbefore set out.

(2) That *subpoena duces tecum* sought by Michigan Gas should be granted as hereinafter ordered.

The Commission orders:

(A) The Settlement proposed by the aforementioned First and Second Stipulations is hereby rejected.

(B) These matters are hereby remanded to the Presiding Examiner for further proceedings not inconsistent with this order.

(C) The application for a *subpoena duces tecum* filed herein by Michigan Gas on November 28, 1961, is hereby granted insofar as it requests that Michigan Wisconsin produce:

(1) A map of Michigan Wisconsin's natural gas pipeline system, indicating thereon the length and pipe size of all lines.

(2) For each separate line other than the main transmission line, a statement setting out the (a) pre-construction estimated cost of construction; (b) the actual cost of construction; (c) the pre-construction estimated third-year sales; and (d) the actual third-year sales, or in those instances where such separate line has not been in operation for a period of three years, the actual sales for the most recent twelve-month period that coincides with the twelve months of the first- or second-year pre-construction estimates.

(D) Within thirty days from the date of issuance of this order, Michigan Wisconsin shall supply to Michigan Gas the material and data set out in paragraph (C) above, and at the same time, shall file five copies thereof with the Secretary of the Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NO. CP62-97

FINDINGS AND ORDER PERMITTING AND APPROVING ABANDONMENT OF FACILITIES AND ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 12, 1962)

On October 16, 1961, El Paso Natural Gas Company (Applicant) filed in Docket No. CP62-97 an application pursuant to Section 7(b) of the Natural Gas Act for permission and approval to abandon certain facilities and pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the sale of natural gas to Intermountain Gas Company (Intermountain) for resale to J. R. Simplot Company (Simplot) and Food Machinery and Chemical Corporation (Food Machinery) near Pocatello, Idaho, and to Idaho Portland Cement Company (Idaho Portland) in

Inkom, Idaho, and the operation of certain facilities presently constructed but not in operation, all as more fully set forth in the application.

Applicant is currently selling and delivering natural gas directly to Simplot, Food Machinery, and Idaho Portland for use in their respective plants. Applicant has agreed to sell natural gas to Intermountain for resale to Simplot, Food Machinery, and Idaho Portland in lieu of the direct sales now being made by Applicant. Applicant's existing facilities now utilized in providing direct gas service to Idaho Portland are adequate for the proposed sale to Intermountain for resale to Idaho Portland, but the facilities now utilized in providing direct gas service to Simplot and Food Machinery will not be adequate to accommodate expanded service to Simplot, as contemplated, through Intermountain, and therefore must be enlarged and modified.

Under the mistaken belief that construction of the additional facilities required could be undertaken pursuant to an outstanding authorization, Applicant has commenced and completed construction of approximately 4,839 feet of 6⅝-inch O.D. loop pipeline, paralleling a segment of Applicant's existing lateral line presently serving the Simplot and Food Machinery plants, and a master metering and regulating station situated at the point of commencement of said loop pipeline, which facilities, will be required primarily to meet increased requirements for the Simplot plant after expansion now in progress. Applicant states that these facilities will not be placed in operation until receipt of the necessary authorization in this docket and that it will continue to deliver gas through the previously authorized facilities until such authorization is received.

The facilities proposed for abandonment consist of approximately 2,118 feet of 3½-inch O.D. pipeline and two metering and regulating stations. The pipeline and one of the metering and regulating stations are now being used to effect deliveries to Simplot, and the other metering and regulating station is being used to effect deliveries to Food Machinery. Applicant proposes to continue these facilities in operation in conjunction with the new facilities for a period of time after placing the new facilities in operation. Thereafter, Applicant proposes to retire and remove the metering and regulating stations and to abandon the pipeline in place. Intermountain will construct individual meter stations downstream from Applicant's master meter for measurement of gas delivered to the Food Machinery and Simplot plants.

The estimated gas requirements under the subject application for the first three years of operation are as follows:

Date	Annual (Mcf)	Peak Day (Mcf)
1962	2,116,337	9,343
1963	2,687,380	12,060
1964	2,687,380	12,060

The estimated cost of construction of the proposed facilities is $40,100, and cost of removal and repair of existing facilities is $3,800, to be financed from current working funds supplemented by short-term bank loans as necessary.

The proposed sales and deliveries of natural gas to Intermountain will be made in accordance with firm Rate Schedule DI–1 and interruptible Rate Schedule I–1, Original Volume No. 3 of Applicant's FPC Gas Tariff.

The small volumes of gas involved should not appreciably affect Applicant's overall system gas reserves.

Temporary authority was issued to Applicant on November 24, 1961.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 3, 1962, respecting the matters involved in and the issues presented

by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, El Paso Natural Gas Company, a Delaware corporation having its principal place of business in El Paso, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 29, 1942, in Docket No. G–242 and G–257 (3 FPC 851).

(2) The sales of natural gas and the transmission facilities to be abandoned, as hereinbefore described and as more fully described in the application in this proceeding, are subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(3) The new facilities hereinbefore described, as more fully described in the application in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof and the transportation and sale of natural gas by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(5) The abandonments heretofore referred to are permitted by the public convenience and necessity and should be permitted and approved as hereinafter ordered.

(6) The construction and operation of the proposed facilities and the proposed sale of natural gas by Applicant to Intermountain are required by the public convenience and necessity and a certificate therefor shall be issued as hereinafter ordered and conditioned.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Permission for and approval of the abandonment by Applicant, El Paso Natural Gas Company, of the sale of natural gas and the facilities hereinbefore described, all as more fully described in the application in this proceeding, be and the same is hereby granted.

(B) Applicant shall advise the Commission of the date of the abandonments permitted in paragraph (A) above within ten days from the date thereof.

(C) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, El Paso Natural Gas Company, to construct and operate the proposed facilities and to sell and deliver natural gas to Intermountain, as hereinbefore described and as more fully described in the application herein, upon the terms and conditions of this order.

(D) The certificate issued by paragraph (C) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(E) The facilities authorized in paragraph (C) above shall be placed in actual operation and the sales of natural gas authorized through said facilities shall commence within six months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NATURAL GAS COMPANIES—EXEMPT FACILITIES, DOCKET NO. R-205

ORDER NO. 241 AMENDING SECTION 2.55 OF THE COMMISSION'S GENERAL RULES AND REGULATIONS

(Issued January 12, 1962)**

The Commission has before it for consideration an amendment to § 2.55 of Part 2, Subchapter A, General Rules, Chapter I of Title 18, Code of Federal Regulations.

Section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)) requires, *inter alia*, a certificate of public convenience and necessity issued by the Commission for any proposed construction or extension of natural gas facilities subject to the jurisdiction of the Commission. Section 2.55 of the Commission's rules (18 CFR 2.55) interprets the word "facilities" as used in section 7(c) of the Act to exclude from the requirement for certification certain types of facilities therein described. The pertinent portions of that section here under consideration are set forth in the margin.*

• • • • • • •

Questions have arisen in the past concerning the meaning of the word "unserviceable" and the clause "*Provided, further,* That such replacement does not appreciably change the daily delivery capacity of the existing transmission pipeline system" in § 2.55(b) and the words "local community presently served" in § 2.55(c). Accordingly, we are adopting amendments to those subsections for purposes of clarification.

The Commission finds:

(1) The amendments herein adopted represent matters of interpretation which do not require notice or hearing under section 4(a) of the Administrative Procedure Act.

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*Section 2.55 *Definition of Term Used in Section 7(c).* For the purposes of section 7(c) of the Natural Gas Act, as amended, the word "facilities" as used therein shall be interpreted to exclude:

(b) *Replacement of facilities.* Facilities which constitute the replacement of existing facilities which have or will soon become unserviceable: *Provided,* That such replacement will not result in a reduction or abandonment of service rendered by means of such facilities: and, *Provided, further,* That such replacement does not appreciably change the daily delivery capacity of the existing transmission pipeline system.

(c) *New delivery points.* Metering and regulating installations and branch lines necessary to the establishment of new delivery points required for the delivery of gas to an existing customer for resale in a local community presently served from the same pipeline system by such customer.

**Published in Federal Register January 18, 1962, DC 41 (27 F.R. 510).

(2) Adoption and promulgation of the proposed amendments are necessary and appropriate for the purposes of administration of the Natural Gas Act.

The Commission, acting pursuant to the authority granted by the Natural Gas Act, as amended, particularly sections 7 and 16 thereof (52 Stat. 824, 830; 56 Stat. 83; 15 U.S.C. 717f, 717o), *orders*:

(A) In § 2.55 of Part 2, Subchapter A, General Rules, Chapter I of Title 18 of the Code of Federal Regulations, subsections (b) and (c) are amended to read as follows:

"(b) *Replacement of facilities.* Facilities which constitute the replacement of existing facilities which have or will soon become physically deteriorated or obsolete to the extent that replacement is deemed advisable: *Provided*, That such replacement will not result in a reduction or abandonment of service rendered by means of such facilities: *Provided further*, That such replacement shall have substantially equivalent designed delivery capacity as the particular facilities being replaced.

(c) *New delivery points.* Metering and regulating installations and branch lines necessary to the establishment of new delivery points required for the delivery of gas to an existing customer for resale in a local community presently served from the same pipeline system by such customer: *Provided*, That the "local community presently served" shall include only the area in which distribution facilities are being operated by the distributor company, but shall not include any area outside the distribution system or beyond the confines of the community, whether incorporated or not, presently being served by the natural gas company's pipeline system."

(B) The statement and amendments herein prescribed shall become effective February 12, 1962.

(C) The Secretary shall cause prompt publication of this order to be made in the Federal Register.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

SOUTHWEST GAS CORPORATION, DOCKET NO. CP62-110

ORDER DEFINING ISSUES

(Issued January 12, 1962)

By notice issued on December 29, 1961, the application of Southwest Gas Corporation (Southwest), for a certificate of public convenience and necessity, authorizing the acquisition and operation of the facilities of Nevada Natural Gas Pipe Line Co. (Nevada Natural), by the Applicant, was set for an abridged hearing commencing on January 25, 1962, concerning the matters involved in and the issues presented by such application.

In addition to the questions generally considered in connection with an application for a certificate of public convenience and necessity, it appears to be in the public interest that the Commission also consider, more specifically, whether the application, which involves a proposed merger of the Applicant with an interstate pipeline, should be granted in light of the policies and provisions of the antitrust laws of the United States. For this reason the Commission is of the opinion that a formal, rather than an abridged, hearing should be held in this proceeding.

The Commission finds:

(1) Southwest has filed an application under Section 7 of the Natural Gas Act for permission, *inter alia*, to acquire the jurisdictional facilities of Nevada Natural, which acquisition will result from the merger of Nevada Natural with Southwest through the exchange of stock between the two companies.

(2) Southwest proposes to continue all the sales and services presently rendered by Nevada Natural and the latter company will cease to exist, if the Commission approves the proposed merger.

(3) It is necessary and appropriate in the public interest that the Commission, in considering whether to approve the acquisition of the facilities of Nevada Natural by Southwest take into account the policies and provisions of the antitrust laws.

The Commission orders:

(A) The Applicant, Southwest, shall submit evidence *inter alia* indicating whether its proposed acquisition of the facilities of Nevada Natural would be consistent with the policies of the antitrust laws.

(B) The hearing on the application of Southwest, filed in Docket No. CP62–110, shall convene for formal hearing at the same time and date provided for in the original notice of application, issued December 29, 1961.

PANHANDLE EASTERN PIPE LINE COMPANY, DOCKET NO. CP60–103; SHELL OIL COMPANY, DOCKET NO. CI60–660; PIONEER PRODUCTION CORPORATION, DOCKET NO. CI60–689; CALVERT PETROLEUM COMPANY, DOCKET NO. CI60–691; ASHLAND OIL & REFINING COMPANY, DOCKET NO. CI60–738; UNION OIL COMPANY OF CALIFORNIA, DOCKET NO. CI60–802; KING-STEVENSON OIL COMPANY, INC., DOCKET NO. CI60–813.

OPINION AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 15, 1962)*

Syllabus

1. While Policy Statement contemplates changes in area boundaries and price levels as facts coming before Commission compel such adjustments, it should not be construed as suggesting that changes will readily be made in individual proceedings; only a very compelling showing would warrant any change on case by case basis. P. 42.
2. Conceding possibility, as Producers contend, that present division of Oklahoma counties into Panhandle and "Other" areas is inequitable and should be changed, present record does not permit such a finding and evidence is insufficient to show that any boundary other than present one is proper. P. 43.
3. Should current review of area boundaries result in increase in initial wellhead price level for new gas in area of sales here proposed, producer applicants may substitute new rates reflecting the increase and thereafter collect such rates prospectively in lieu of initial rates herein required. P. 42.

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* Designated Commission Opinion No. 350; Initial decision appears on p. 53. Clarifying order printed at p. 52. Rehearing denied by order issued March 9, 1962, 27 FPC 491.

4. Finding no *compelling* evidence to justify an initial wellhead price in excess of area ceiling, Commission *conditions* certificates for proposed sales in "Other" Oklahoma at initial wellhead price of 15 cents per Mcf. P. 44.
5. Since 15 cents area ceiling price in Elk City field is based on wellhead sales, Shell is permitted to recover as part of initial price so much of cost of gathering, dehydration and compression as is properly allocable to Elk City sale. P. 45.
6. Absent cost of service evidence Commission allows Shell 2.5 cents per Mcf for services beyond wellhead in sale of Elk City gas to Panhandle and conditions certificate at total initial price of 17.5 cents per Mcf. P. 45.
7. Size of reserves and high initial availability of gas are not factors to be considered in fixing Shell's price for Elk City gas; apart from some specific service or forbearance or special circumstances, value of gas to pipeline purchaser is not a consideration in certification of initial prices under area pricing policy. P. 45.
8. Rate-of-take provisions in producer contracts *allowed* (15 years Elk City; 20 years en route); there being no suggestion of a resulting overall deliverability life of Panhandle reserves less than that which is usually required. P. 46.
9. Commission *allows* take-or-pay and Btu adjustments in producer contracts subject to final determination in rule-making proceedings (R–199; R–200). P. 46.
10. Producer applicants who cancelled contracts allowed to resubmit applications on terms and conditions originally applied for; in such event applications shall be reinstated and certificates issued *Nunc pro tunc* on same terms and conditions as other producers. P. 49.
11. Commission *issues* certificates of public convenience and necessity to applicants under Section 7 of the Natural Gas Act. P. 50.

Raymond N. Shibley for Panhandle Eastern Pipe Line Company.

Oliver L. Stone and *Joseph C. Spalding* for Shell Oil Company.

W. N. Lampe, Charles E. McGee, R. E. Christiansen, and *James D. McKinney, Jr.* for Pioneer Production Corporation.

Bruce R. Merrill and *Tom Burton* for Calvert Petroleum Company.

G. F. Charles for Ashland Oil and Refining Company.

George D. Horning, Jr. and *J. Colin Lizotte* for Union Oil Company of California.

Lewis G. Mosburg, Jr. for King-Stevenson Oil Company, Inc.

George C. Williams, Robert C. Weber, C. William Cooper, Lawrence L. Gray, and *Norman A. Flaningam* for The East Ohio Gas Company.

George P. Lewnes for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

O'CONNOR, *Commissioner:*

This consolidated proceeding involves applications for certificates of public convenience and necessity under sections 7(c) and 7(e) of the Natural Gas Act.

Panhandle Eastern Pipe Line Company (Panhandle) seeks authority to build a 200-mile lateral from its Haven compressor station in central Kansas to Shell Oil Company's Elk City gas field in western Oklahoma. Shell and the other producer applicants seek authority to sell gas to Panhandle, Shell's gas to be delivered to Panhandle at Elk City, and the gas from the other producers to be picked up by Panhandle en route along the new lateral from other fields located in western and northern Oklahoma.

The main issue in this proceeding is the proper initial price to be charged by the producers, with ancillary questions with respect to Btu adjustment, rate of take, and take-or-pay provisions in the producers' contracts with Panhandle. Panhandle has agreed to pay Shell a base initial price of 20.5 cents per Mcf for gas from the Elk City field, which lies mostly in Beckham County and partially in Washita County. Panhandle has contracted with the other producers to pay a base initial price of 17 cents per Mcf for gas from fields in Woodward, Woods, Dewey, Major and Alfalfa Counties.[1]

The Commission's Statement of General Policy No. 61–1, issued September 28, 1960, sets up three pricing areas in Oklahoma with initial price ceilings as follows: The Panhandle area, embracing six counties in northwest Oklahoma, with an initial price level of 17 cents per Mcf. The Carter-Knox area, embracing those portions of Grady and Stephens Counties in south-central Oklahoma known as the Knox field, with an initial price level of 16.8 cents per Mcf. And an area designated as "Other", embracing the rest of the State of Oklahoma, with an initial price level of 15 cents per Mcf.

In this proceeding, Pioneer Production Corporation and Ashland Oil & Refining Company propose sales in Woodward County in the Panhandle area. All of the other sales fall within the "Other" Oklahoma area. Panhandle and the producers contend that there is no sound basis for differentiating between the Woodward sales at 17 cents and the other en route sales; that all of the 17-cent sales are comparable to existing certificated sales in the Panhandle area; and that the evidence of record compels the conclusion that the public convenience and necessity require certification of these sales as contracted.

With respect to the Elk City sale, Panhandle and Shell contend that presently certificated sales in the Panhandle area constitute the proper basis for making a comparison, and that the unique features of the Elk City sale, as more fully discussed below, more than justify the proposed price of 20.5 cents.

The Commission's staff contends that all of the proposed prices, except for Woodward County sales, should be conditioned at 15 cents, the initial price level for the "Other" Oklahoma area; that the proper comparison to be made in evaluating the proposed "Other" Oklahoma sales is with presently certificated sales in that area, and not with sales in the Panhandle area; that there is no compelling evidence of record in this proceeding to justify initial prices in excess of the ceilings established in the Policy Statement; and that neither the ceiling levels nor the area boundaries may properly be altered in individual certificate proceedings. Staff also urges the imposition of conditions eliminating any upward Btu price adjustment, reducing rate of take to one Mcf per day for each 8,000 Mcf of recoverable reserves and reducing take-or-pay to 80 percent of annual contract quantities.

On July 11, 1961, the examiner who presided at the hearing in this proceeding issued his initial, or recommended, decision. The examiner's decision would grant certificates of public convenience and necessity to each of the applicants without conditions as to price, Btu adjustment, rate of take, or take-or-pay. The examiner found that Panhandle and its customers have a need for the gas supply here proposed, and that the facilities to be installed are soundly engineered and financed, and are economically feasible. A description of Panhandle's operations and a more detailed discussion of its need for this gas are to found in the examiner's comprehensive decision, and are not repeated here.

With respect to the producer applications, the examiner's conclusion that certificates should be issued without condition as to price is based on his construc-

[1] All prices referred to herein are at 14.65 psia.

tion of the Policy Statement, and a consideration of geological, geographical and marketing factors, as well as factors measuring the value of the proposed gas supply to Panhandle.

As construed by the examiner, the Policy Statement gives scope to a consideration of the basic facts of geology, market area history, and oil and gas economics in the pricing of new gas supplies. It is his belief that the Commission can and should make changes in the area ceilings and in the area boundaries in accordance with such facts and the public interest as found in specific proceedings. And upon consideration of such factors in the present proceeding, the examiner concludes that 17 cents per Mcf should be established as the area price for new gas sold from the Oklahoma counties of Woods, Alfalfa, Woodward, Major and Dewey. These include the counties presently in the "Other" Oklahoma area from which the proposed en route sales are to be made. The examiner would also extend this 17-cent area to include gas (except Elk City gas) sold from Beckham and Washita Counties. With respect to Elk City, the examiner would incorporate that field into the general area pricing patterns established by the Policy Statement at an initial price level of 20.5 cents per Mcf, in the same way as the Knox field was incorporated as a separate pricing area.

The examiner finds that the entire upper Oklahoma gas producing region lies in the Anadarko Basin, and constitutes a single geological province; that the producing horizons trend downward to greater depths from the Colorado-Oklahoma border southeasterly through the counties here involved; and that the productive formations in this proceeding are common to the entire area known generally as the Texas-Oklahoma Panhandle. He finds that with respect to marketing, geography, and well-drilling and operating attributes, the Elk City and en route conditions are similar to those of the Laverne field in the 17-cent Panhandle area designated in the Policy Statement, except that Laverne is shallower and less expensive to drill and operate. Apart from the suggestion that any distinction between the Panhandle area and the area of the presently proposed sales should reflect higher prices for the latter if the Commission wishes to provide an incentive to encourage the exploration and development of deeper formations, the examiner concludes that there is no basis for differentiating between these areas, or the adjoining area in Texas Railroad District No. 10, which like the Oklahoma Panhandle area has an initial price ceiling of 17 cents per Mcf.

The examiner gives controlling weight to a consideration of the value to Panhandle of the Elk City gas in finding that the 20.5-cent initial contract price is required by the public convenience and necessity. Unlike the en route gas, the Elk City gas is gathered, dehydrated and compressed, and it represents a unique supply in terms of the size of the recoverable reserves and its deliverability. The examiner concludes that the contract price reflects the value of the gas to Panhandle, and on this basis is not out of line on a comparison with other sales; and that the consumer is not prejudiced by this price even though the return to the producer might be excessive or inordinate according to traditional utility cost concepts.

The evidence of value which the examiner relies on is found in a hypothetical study by Panhandle of a possible alternative supply of gas from sources located as near as possible to its main line through Kansas and Oklahoma. This study shows what it would cost Panhandle to gather, process and compress a comparable supply of gas. On the basis of this study, as well as evidence of Panhandle's actual costs for gathering recently acquired supplies and for current field compression, the examiner finds that Panhandle is advantaged to the extent of five to six cents per Mcf by Shell's gathering, dehydrating and compressing services at Elk City.

With respect to the enroute supply, the examiner finds that the value of this gas is at least the equivalent of those values which have been translated into existing prices elsewhere in the Anadarko Basin, particularly in the Texas-Oklahoma Panhandle region.

Turning to the ancillary issues, the examiner finds that a condition eliminating the upward Btu adjustment provisions in the producer contracts is not necessary to protect the consumer, and would discriminate unfairly against these producers by eliminating a contract provision not unusual in this area and one heretofore approved by the Commission in other certificate proceedings. Noting that the question of eliminating upward Btu adjustments is presently before the Commission in Docket No. R–200, a rule-making proceeding, the examiner concludes that the proper procedure for effecting a general policy as to such adjustments is through that proceeding, and not through piecemeal determinations in individual certificate proceedings such as the present case.

The examiner finds that the rate of take provisions in both the Elk City and en route contracts are in the public interest. The Elk City contract provides for depletion of recoverable reserves over a 15-year period. The en route contracts provide for depletion over a 20-year period. Panhandle, the examiner finds, needs the gas for existing customers and will be able to use it to correct the present overproduction of existing supplies, so that both Panhandle and its customers will benefit by the high takes. The examiner also finds the contract take-or-pay provisions to be advantageous to Panhandle and consonant with the public interest, noting that Panhandle has never had to pay for gas not taken, and that there is no likelihood of it having to do so now. As in the case of the Btu adjustment, the question of fixing standards for rate of take and take-or-pay provisions in producer contracts is before the Commission in a rule-making proceeding in Docket No. R–199, and the examiner here again suggests that such matters of general policy should properly be determined in that proceeding rather than in the instant case.

Exceptions to the examiner's decision were filed only by the Commission's staff. Staff's principal exceptions are directed to (1) the examiner's interpretation of the Policy Statement, (2) his reliance on value of service in determining the proper initial prices, and (3) his approval of the Btu adjustment, rate of take, and take-or-pay provisions as being in the public interest. It is staff's position that the certificates, if issued, should be conditioned to require initial prices not in excess of those set forth in the Policy Statement, and that the Btu adjustment, rate of take, and take-or-pay provisions should be revised to conform to the standards proposed by the Commission in Docket Nos. R–199 and R–200.

Staff contends that the examiner erred in construing the Policy Statement to allow or to require the change of area ceilings or boundaries in individual certificate proceedings. The only issue in the present proceeding as to price, in staff's view, is whether the applicants have adduced evidence of such a compelling nature as to justify a price for sales in the "Other" Oklahoma area over the 15-cent ceiling set in the Policy Statement. This, says staff, the applicants have failed to do. Such evidence should not merely consist of comparative evidence peculiar to any given area, but evidence specifically related to the operations of each applicant; and the present record is devoid of such evidence. There is no evidence, says staff, to show that the 15-cent area ceiling price will not afford the producers a fair return, or that a higher price is necessary to assure further exploration and development in the area.

With respect to the Btu adjustment, staff questions the benefit of higher Btu gas to either the pipeline or the consumer. It objects to allowing an upward price adjustment for gas over 1,000 Btu's because the effect is to require

the consumer to pay a premium for Btu's which are of no benefit to him. Staff further contends that there has been no showing of the necessity for such an adjustment, and that it should therefore be eliminated.

Staff's exceptions to the examiner's approval of the rate of take and take-or-pay provisions reflect a concern for the general problem of maintaining adequate deliverability life for pipeline reserves. Staff does not contend that these contract provisions will here result in an overall deliverability life of Panhandle's reserves less than that usually required by the Commission. Rather, it objects to these provisions on the ground that they provide for depletion of the dedicated reserves at a rate in excess of that usually found in the industry, and in excess of that which the Commission has proposed as a matter of general policy in Docket No. R–199. Staff also notes that early depletion is of value to the producers, and takes the position that if these provisions are allowed, the initial prices should be fixed at correspondingly lower levels than those appearing in the Policy Statement.

Upon request of the applicants, oral argument before the Commission of the issues raised by staff's exceptions to the examiner's decision was granted, and was held on November 2, 1961.

We are of the opinion that certificates of public convenience and necessity should be issued to Panhandle and to the producer applicants. We shall, however, condition the certificates issued to the producers to require the filing of initial prices of 15 cents per Mcf for gas sold to Panhandle from fields, other than Elk City, in the "Other" Oklahoma area. In recognition of Shell's services to Panhandle beyond the wellhead at Elk City, which distinguish it from the other sales to Panhandle in the "Other" Oklahoma area, we shall allow Shell to file an initial price of 17.5 cents per Mcf for the Elk City gas. We shall allow the Btu adjustment, rate of take, and take-or-pay provisions in the producers' contracts; subject, however, to our determination in Docket Nos. R–199 and R–200 with respect to take-or-pay and Btu adjustment, and to such further conditions as are hereinafter set forth.

The record shows that Panhandle has a need for the gas which the producers here propose to sell to it, and that its proposed lateral facilities are economically and financially feasible and well designed. Rather than repeat the examiner's discussion and findings with respect to Panhandle's project, we here adopt the treatment and disposition of Panhandle's application as made in the examiner's decision.

Before considering the important issues which have been raised with respect to the producer applications, it will be helpful to set forth the basic features of the producer contracts and certain facts of record which reveal the character and nature of the proposed sales.

The 17-cent en route contracts generally reflect the pattern of wellhead sales heretofore certificated by the Commission in the Panhandle area of Oklahoma, and typified by sales from the Laverne field in Harper County, adjoining Woodward County on the northwest. The contracts for the en route sales contemplate a term based on a 20-year deliverability life for the dedicated reserves, and provide for periodic escalations of 2.5 cents per Mcf every five years. They contain both upward and downward Btu price adjustments for Btu content above and below 1,000 Btu's per cu. ft., with a maximum upward adjustment based on 1,200 Btu's. The adjustment is directly proportional to the actual Btu content of the gas. The average daily contract quantities which Panhandle is required to take are equivalent to a ratio of one Mcf for each 7,300 Mcf of recoverable reserves, providing a 20-year life. Panhandle is required to take or pay for these contract quantities on an annual basis, although it may vary its daily takes above and below these amounts. Any

annual deficiency paid for but not taken may be made up over a two-year period. Any annual excess may be applied as a credit against deficiencies in subsequent years. The contracts involve a dedication of some 60,432 acres, of which 7,114 are proven with total proven reserves of 57,360,000 Mcf.

The Shell Elk City contract provides for an initial price of 20.5 cents per Mcf with escalations of 2.5 cents per Mcf every five years during its term. The term of the contract is 20 years, although it is the expressed intent of the contract that the recoverable reserves at Elk City be depleted in the first fifteen years. Unlike the en route contracts, this contract requires Panhandle to reimburse Shell for a share of current taxes. This payment, amounting to 50 percent of Shell's taxes, is in addition to the base initial price of 20.5 cents per Mcf. The contract also provides for both an upward and downward adjustment of price for Btu content above and below 1,000 Btu's per cu. ft. The adjustment is similar to that in the en route contracts and is limited to a maximum upward adjustment based on 1,200 Btu's. Annual contract quantities are based on average daily deliveries of 125,000 Mcf in the first, fourth and fifth years, 135,000 Mcf in the second and third years, and daily deliveries of one Mcf for each 3,650 Mcf of recoverable reserves in the sixth and subsequent years. Panhandle has an option to increase the annual contract quantities during the first five years to the equivalent of 180,000 Mcf per day. Panhandle is required to take or pay for the annual contract quantities, although it may vary its daily takes 25 percent above and below the average daily contract quantity. Any annual deficit must be paid for, but may be made up during the following three years. Exess takes in any year may be carried forward as a credit toward the required takes in the following three years.

Certain other facts of record with respect to the Elk City field and Shell's contract with Panhandle may be summarized briefly as follows:

(1) The Elk City field is a developed field of some 11,800 acres, containing nine producing reservoirs between 8,950 and 10,900 feet deep, and tapped by 295 producing wells.

(2) The field was discovered in 1947 and unitized in 1950. Shell is 75 percent owner and the operator of the field. To date the field has been operated for the recovery of liquids by cycling and reinjection of the gas; but the production of liquids has now diminished to the point that the field should be operated as a gas field. Recycling is scheduled to stop at the end of 1963, or sooner should Panhandle's takes so require.

(3) Reserves in place total 807,893,000 Mcf, of which 746,316,000 Mcf are recoverable. Allowing for shrinkage and fuel, 701,536,000 Mcf will be available to Panhandle. This is to be compared with the aggregate reserves acquired by Panhandle under 162 separate purchase contracts from January 1, 1955, to January 1, 1960, and totaling 607,125,000 Mcf.

(4) The field has a proven ability to deliver at a rate in excess of 240,000 Mcf per day, and under the contract Panhandle has the option during the first five years to take as much as 225,000 Mcf per day. With the right to vary its takes as much as 25 percent above and below the average daily contract quantities, and considering the size of the contract quantities provided, Panhandle is permitted great flexibility in its takes.

(5) Unlike other sales in this area, which are usually wellhead sales, the Elk City gas is to be gathered, dehydrated and compressed by Shell, and delivered to Panhandle at a central point at a pressure of 825 psig. The quality and pressure of the gas as delivered to Panhandle will be such as to permit Panhandle to transmit it through its lateral without additional processing or compression.

(6) Shell's wells and surface facilities at Elk City represent a direct investment of $75 million. Shell will spend $200,000 to $300,000 immediately for dehydration equipment, and over the life of the contract expects to spend some $6 million more for additional compression and changes in its gathering system.

(7) The Elk City gas insures the basic supply necessary to support the feasibility of Panhandle's proposed lateral.

(8) The contract provides for depletion of the Elk City reserves over a 15-year period instead of the usual 20- or 22-year period. It was Panhandle's willingness to take the reserves over a shorter period of time that led Shell to sell the gas to Panhandle at an initial contract price lower than that offered by other pipeline purchasers.

With respect to both the 17-cent contracts and the Elk City contract, the record shows: (1) no affiliation between the producers and Panhandle, (2) arms' length bargaining of the contracts, (3) a need for the gas by Panhandle, (4) no triggering of prices, and (5) no favored nations, spiral escalation, or other indefinite pricing provisions.

Turning now to a consideration of the issues presented by the producers' applications, we shall first dispose of the questions as to area and initial price, and then take up the ancillary questions as to Btu adjustment, rate of take, and take-or-pay.

In an effort to find appropriate means for bringing about effective regulation of independent producers of natural gas, and to thus carry out the mandate of the United States Supreme Court in the *Phillips*[2] and *CATCO*[3] cases, the Commission has adopted a policy of area pricing. In the Statement of General Policy No. 61–1, issued September 28, 1960, and subsequently amended, the Commission established area price standards to be applied in determining the acceptability of initial price proposals as well as increased rate filings by producers. It was our opinion then, and is our opinion now, that these standards are an effective aid in applying the provisions of the Natural Gas Act to independent producers on "a simple, clear and administratively feasible basis," and in a manner "fair to all whose interests are affected by Commission regulation."

The area price levels, as set forth in the Policy Statement and its amendments, are "for the purpose of guidance and initial action by the Commission," and do not constitute determinations of just and reasonable prices. The Policy Statement contemplates changes in both area boundaries and area price levels from time to time as such facts as come before us compel such adjustments.[4] The Policy Statement, however, should not be construed as suggesting that changes in either area boundaries or prices will readily be made in individual proceedings. It would defeat our purpose of simplifying and clarifying producer regulation, if every individual proceeding were to become a forum for attacking the area standards and we were to begin varying those standards from case to case. Adjustments in the area price structure can best be made upon a general review of all relevant factors. At the least, it would take a very compelling showing to warrant any change on an *ad hoc* basis.

In the present proceeding, the producers have adduced evidence attempting to show that from the point of view of geology, geography, marketing, and operating, the gas producing fields in the "Other" Oklahoma counties here involved are similar to fields in the Panhandle area where we have fixed an initial wellhead price of 17 cents per Mcf. The evidence, however, does not

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[2] *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 674.

[3] *Atlantic Refining Co.* v. *Public Service Commission*, 360 U.S. 378.

[4] Area rate hearings are presently being conducted with respect to the Permian Basin, Docket Nos. AR61–1, *et al.*, and Southern Louisiana, Docket Nos. AR61–2, *et al.*

show that there is not a like similarity with other fields in the "Other" Oklahoma area which lie to the east and which are also in the Anadarko Basin. It is possible, as producers contend, that the present division of Oklahoma counties into the Panhandle and "Other" areas is inequitable and should be changed; but the present record does not permit us to so find, and there is insufficient evidence to show that any boundary other than the present one is proper.

As we stated in the Policy Statement, the geographical areas "are not necessarily in complete accord with geographical and economic factors which may be relevant to the establishment of pricing areas." And we there noted that "as experience and changing factors may indicate, we will change or alter these areas from time to time in order to eliminate such inequities as may appear to exist because of our use of geographical boundaries." The Commission recognizes that there is a present need for a general review of the boundaries of the areas established by the Policy Statement to determine the existence of any inequities. To this end, the Commission is currently making such a review of area boundaries in light of information acquired since the areas were first delineated, and giving consideration to relevant geological, geographical, marketing and operating data available to it. We expect to complete this study within the next few months, at which time any necessary changes in the present area boundaries will be made by issuance of an amendment to the Policy Statement.[5] Should this study result in an increase in the initial wellhead price level for new gas in the area of the sales here proposed, because of an adjustment in the area boundary between the Panhandle and "Other" Oklahoma areas, the producer applicants accepting the certificates herein issued may thereupon substitute new rates reflecting the amount of such increase, and thereafter collect these new rate prospectively in lieu of the initial rates herein required.

The initial price level for new service established by Policy Statement No. 61–1 is 17 cents per Mcf in the Panhandle area and 15 cents in "Other" Oklahoma. The ceiling for increased rates in the same areas is 11 cents. In explaining our use of the Policy Statement price levels, we therein stated that:

> For the present, and in the absence of compelling evidence calling for other action by us, proposed initial sales of natural gas by independent producers which include rates higher than those indicated in * * * this statement shall be denied a certificate or certificated only upon the condition that lower rates be filed, and all rate changes filed under existing contracts which call for a rate exceeding the indicated price level * * * shall be suspended.

The Policy Statement further shows that it is the Commission's intention to determine the justification of proposed prices in excess of the indicated levels in area proceedings, wherein all elements relevant to the industry generally in the area concerned will be considered, and the price determined will be an area price and not necessarily a price applicable solely to the party proposing the higher price.

There is no evidence in the record now before us which compels the conclusion that a wellhead price of 17 cents per Mcf for the proposed sales in the "Other" Oklahoma area is required in the public interest. The applicants rely on comparative evidence to show that the conditions of developing, produc-

[5] In accordance with our announced intention to make changes in the Policy Statement from time to time, we have heretofore issued amendments changing price levels in certain Texas Districts and in Southern Louisana. See Third Amendment, March 29, 1961, and Fourth Amendment, October 31, 1961, 25 FPC 595 and 26 FPC 661, respectively.

ing and marketing gas in the fields here involved are similar to conditions in the Laverne and other fields in the Panhandle area where the Commission has certificated wellhead sales at 17 cents. This evidence is not sufficient to justify a wellhead price for the proposed sales in excess of the "Other" Oklahoma ceiling level. The record shows that the highest certificated price for gas now being sold in that part of the "Other" Oklahoma area which is located within the Anadarko Basin is 15 cents per Mcf.[6] Eight sales at this price level are being made for gas from the West Cement field in Caddo County and the South Rainey field in Washita County just to the east of Elk City.[7] In Beckham County, where Elk City is located, and in Woods and Alfalfa Counties, where some of the en route gas is located, the record shows initial prices certificated at 12 cents per Mcf. Elsewhere in "Other" Oklahoma, and within the Anadarko Basin, the record shows sales certificated at 11 and 12 cents per Mcf in Grant and Garfield Counties. This pattern of presently certificated sales in the area establishes the line for the proposed sales and shows a reasonable relationship between the Policy Statement area ceiling and existing sales. There is no compelling evidence in this proceeding to justify an initial wellhead price in excess of the area ceiling. We shall, therefore, condition the certificates for sales in "Other" Oklahoma at an initial wellhead price of 15 cents per Mcf.[8]

As noted above, the proposed sale by Shell at Elk City does not fit the usual pattern of wellhead sales in this area. Shell contends that the unique features of this sale more than justify the initial contract price of 20.5 cents. We cannot agree that the full amount of the proposed price is justified; but in view of the fact that the ceiling in this area is based on wellhead sales, and that Shell proposes to render services beyond the wellhead in making this sale, we shall allow Shell an increment of 2.5 cents per Mcf above the area wellhead ceiling of 15 cents.[9]

Clearly, the Elk City field represents an unusually desirable supply of gas, and it is understandable that a number of pipelines have sought to acquire this gas from Shell. However, the fact that Panhandle and the other pipelines operating in the area are willing to pay 20.5 cents or more per Mcf to acquire it does not convince us that the proposed price is required in the public interest. Nor does Panhandle's evidence of gathering, dehydration and compression costs persuade us that five to six cents per Mcf should be attributed to these services at Elk City and incorporated as an allowance in the initial price, as found by the examiner.

Panhandle's studies show a current unit cost for gathering, dehydration and compression services on its system of 3.98 cents per Mcf. They also show an estimated cost of 5.03 cents per Mcf to gather, dehydrate and compress a hypothetical alternative supply to the Elk City field, plus an additional one cent per Mcf for future compression to be added to maintain the delivery pressure specified in the Shell contract. Panhandle further estimates its initial cost of rendering these services with respect to the en route gas at 4.03 cents per Mcf. These studies are no doubt indicative of Panhandle's costs, but they do not

[6] The highest price heretofore certificated in all of "Other" Oklahoma is 15.5 cents per Mcf for three sales from the West Enville and Southwest Enville fields in Love County along the southern Oklahoma-Texas border.

[7] *Natural Gas Pipeline Co., et al.*, 24 FPC 222.

[8] With respect to those sales of en route gas to be made in the Panhandle area, *i.e.*, from Woodward County, we shall allow the proposed initial price of 17 cents per Mcf, which is in line with the Policy Statement ceiling for new service in that area.

[9] The total initial price, so allowed, shall be inclusive of any reimbursement to Shell for current taxes, thus conforming to other sales, and to the area wellhead price ceiling which is inclusive of such taxes.

necessarily reflect Shell's costs or show how much Shell should be allowed for these services in its initial price for the gas. To properly determine a price for these services which is in the public interest, consideration must be given to Shell's costs in light of the special history of the Elk City field and its development and use by Shell for the production of liquids as well as of natural gas.

Although the record shows that Shell intends to invest $200,000 to $300,000 initially for dehydration facilities, and thereafter to spend some $6 million more for additional compression and for changes in its gathering system, it also appears that the major portion of the gathering and processing facilities which Shell will utilize in delivering the Elk City gas to Panhandle are already installed, and in fact have been in use during the past ten years for the production and sale of liquids—a non-jurisdictional use. The record, however, does not show the cost of these facilities, or the extent to which their cost has been recovered by Shell through revenues from the sale of such liquids; nor does the record show to what extent the facilities are to be used in the future for the removal and non-jurisdictional sale of liquids as well as for the proposed deliveries of gas to Panhandle.

There is no question but that the gathering, dehydration and compression services which Shell proposes to render at Elk City are beneficial and required in the public interest; and that if Shell were to sell this gas to Panhandle at the wellhead without these services, it would be necessary for Panhandle to install its own facilities to gather, dehydrate and compress the gas, with a resulting increase in cost to Panhandle's jurisdictional customers. Under these circumstances, and where, as here, the 15-cent area ceiling price is based on a prevailing practice of making sales at the wellhead, Shell should be permitted to recover as part of its initial price so much of its cost of gathering, dehydration and compression as may be properly allocable to the sale of gas to Panhandle. However, in the absence of cost-of-service evidence, and evidence as to what portion of Shell's cost may be justifiably allocated to its jurisdictional sale of gas, we cannot determine with precision the amount to be allowed for Shell's services. In the circumstances we shall allow Shell an amount which in our judgment is reasonable, both for Shell and for the gas consumer who must ultimately pay for the services. The amount allowed is one which, we are satisfied, could be readily justified were we to remand the proceeding for the taking of additional evidence. Shell is certainly entitled to no more in light of its presentation. Thus, we shall allow Shell 2.5 cents per Mcf for recovery of the cost of its services beyond the wellhead in connection with the sale of the Elk City gas to Panhandle. We shall accordingly condition the certificate herein issued to Shell upon the filing of a total initial price of 17.5 cents per Mcf, including tax reimbursement, based upon a price of 15 cents for gas at the wellhead, the "Other" Oklahoma ceiling level for wellhead gas, plus 2.5 cents for gathering, dehydration and compression.

Shell and Panhandle urge that other features of the Elk City sale, besides the gathering, dehydration and compression services, should be considered in determining Shell's initial price. Such features as the size of the reserves and the high initial availability of the gas may enhance the desirability of the Elk City gas to Panhandle; however, they are not factors which, in our judgment, should be considered in fixing Shell's price. The area price standards set forth in the Policy Statement not only contemplate the sale of gas of pipeline quality, but also the dedication with respect thereto of substantial gas reserves. Apart from some specific service or forbearance in connection with a sale of gas, or some circumstance with respect to the conditions of its sale which affects its character as pipeline quality gas, the value of the gas to the pipeline purchaser

is not a consideration in the certification of initial prices under our area pricing policy.[10]

There remain to be considered the ancillary questions as to the Btu adjustment, rate of take, and take-or-pay provisions in the producer contracts. The Btu adjustment provisions have a direct bearing on the price of the gas to be sold to Panhandle, and we shall give these provisions a closer look in the discussion below. The rate of take and take-or-pay provisions, however, are of a different nature, in that they relate primarily to the more general question of the deliverability life of Panhandle's supply. With respect to these latter provisions, Panhandle seems certain to take all of the gas required under its contracts without any necessity of paying for gas not taken, and no suggestion has been made that the contract rate of take provisions will result in an overall deliverability life of Panhandle's reserves which is less than that usually required by the Commission. However, there is a possibility that the 100 percent take-or-pay provisions in these contracts may at some future time put Panhandle in the position of having to purchase this high cost Oklahoma gas, and to cut back on its own production or low cost supplies purchased under contracts with no take-or-pay provisions, should it find that its customers' demands or its pipeline capacity are less than its production allowables and its contract purchase quantities. This is one of the problems with respect to take-or-pay provisions now being considered by the Commission in connection with the proposal in Docket No. R–199 to standardize take-or-pay provisions in producer contracts at 80 percent. Inasmuch as the minimum take-or-pay provisions to be allowed in producer contracts filed as rate schedules will be determined as a matter of general policy in Docket No. R–199, we shall condition our allowance of the proposed take-or-pay provisions in the instant proceeding so as to make them subject to our determination in the rule-making proceeding, with the proviso, that in no event shall we require these producers to accept provisions for less than 80 percent.

With respect to the upward Btu adjustment provisions, staff would have us condition the certificates to the producers to require their elimination. As stated above, staff questions the benefit of the higher Btu gas to either the pipeline or the consumer, and takes the position that the effect of the upward Btu adjustment is to increase Panhandle's cost of service, thus requiring its resale gas customers to pay for additional Btu's which are in fact no benefit to them.

In passing upon the Btu question in this proceeding, we are not only faced with the substantive objections to the adjustments raised by staff, but with the fact that the question of whether, as a matter of general policy, such adjustments should be allowed in producer contracts, is presently before the Commission in the Docket No. R–200 rule-making proceeding. Because of the importance of these adjustments to the producers in terms of additional revenues,[11] and because we do not wish to deprive the producers of such revenues pending our determination in Docket No. R–200 if they can be reasonably justified in the public interest on the record in this proceeding, we shall undertake to dispose of this issue on its merits. However, our treatment of Btu adjustments in this case should not be construed as in any way prejudging this issue in

[10] If consideration were to be given to the other features of the Elk City contract, we should be obliged to note that Panhandle's agreement to take or pay for Shell's gas over a 15-year period is of unique value to Shell. Indeed, it was Panhandle's willingness to purchase the gas over a shorter period of time that led Shell to sell the gas to Panhandle at a price less than that offered by other pipeline purchasers.

[11] The Elk City gas has an estimated Btu content of 1,050 Btu's per cu. ft. Estimates for the en route gas range from 1,000 to 1,100 Btu's per cu. ft. An adjustment based on 1,050 Btu's would raise a base price of 15 cents per Mcf to 15.75. For 1 100-Btu gas the price would be 16.5 cents per Mcf.

Docket No. R–200, or in any way prejudicing the position or views presented by any producer or other interested person in that proceeding.

The basic question to be answered in deciding whether to allow the proposed upward Btu adjustments to the producer applicants in this proceeding is this: Will the proposed adjustments have any adverse impact upon Panhandle's jurisdictional gas service? If Panhandle's jurisdictional customers will not be required to pay more for their gas requirements as a result of the operation of the price adjustment provisions, as compared to what they would pay if no upward Btu price adjustment were allowed, or if any increase in the cost of jurisdictional gas service is offset by benefits to jurisdictional customers in the form of increased heating value or otherwise, then, in our opinion, the producers should not be deprived of their bargain with Panhandle for the additional Btu's in their gas.

Panhandle is involved in the operation of three processing plants.[12] Two of these, one located at Sneed, Texas, and one in Liberal, Kansas, are for the extraction of gasoline and other liquid hydrocarbons prior to transporting gas through its system. We have held these extraction operations to be part of Panhandle's pipeline business, and have required the revenues therefrom to be offset against Panhandle's jurisdictional cost of service. The third plant is a petro-chemical plant at Tuscola, Illinois. We have held the operation at Tuscola to be non-jurisdictional, with the result that neither the costs nor the revenues associated therewith figure in Panhandle's cost of service. In the case of such a non-jurisdictional operation, gas supply and transportation costs must be allocated between the non-jurisdictional plant use of gas (fuel and shrinkage) and the jurisdictional resale of gas in interstate commerce. At Tuscola we have determined that the gas supply cost should be allocated on the basis of the heat units, or Btu's, removed from the gas stream, and that the transportation costs should be allocated on a volumetric basis.[13]

Gas leaves the Sneed plant at 1018 Btu's. A part of this gas is mixed with 976-Btu gas leaving Panhandle's Liberal plant to form a stream of 987-Btu gas which is transported through Panhandle's low pressure Line 100. This line, which is used to serve customers upstream from Tuscola, by-passes the Tuscola plant. The balance of the 1,018-Btu gas from Sneed is transported through Panhandle's high pressure Lines 200 and 300, and all of this gas passes through the Tuscola plant. This gas leaves the Tuscola plant at 933 Btu's, and is thereafter mixed with the 987-Btu Line 100 gas and 1,038-Btu gas received from its subsidiary Trunkline Pipeline Company and delivered to customers downstream from Tuscola at a uniform 983 Btu's.

It is not clear from the record in this case whether the high Btu Elk City and en route gas is to be delivered through the new Elk City lateral into Panhandle's low pressure Line 100 or into its high pressure lines. To the extent that it is delivered into the low pressure system and mixed with lower Btu gas, it may well result in higher Btu gas to Panhandle's customers upstream from Tuscola.[14] Or, should future gas supplies along the new lateral prove to

[12] The facts herein set forth with respect to Panhandle's plant operations and the Btu content of gas presently being delivered through its system are of record in *Panhandle Eastern Pipe Line Company*, Docket No. G–2506; and the determinations, referred to, as to the treatment of costs and revenues and the allocation of costs at Panhandle's plants, are to be found in our Opinion No. 344 in that proceeding, 25 FPC 787.

[13] The Sneed plant is owned and operated by Phillips Petroleum Co. and the Tuscola plant is owned and operated by National Petrochemical Corp.

[14] Panhandle's tariff, like those of a number of other pipelines, provides for an upward adjustment of resale rates for gas of high Btu content. An increase in Btu content would result in a decrease in the volume of gas sold if the customers serve loads which can utilize the additional Btu's. Where such loads are substantial, there will be a reduction in the volumes of gas sold and the effect on the customers would be negligible.

be of lower Btu quality, the present supply could benefit such customers by helping to maintain the heating value of the gas stream. To the extent that the present supply is delivered into Panhandle's high pressure lines, all of the gas will be transported to Tuscola and there processed in the petro-chemical plant for the removal of the heavier hydrocarbons. The additional Btu's in the gas will thus be removed for Panhandle's benefit, and Panhandle's downstream customers will not benefit thereby through the receipt of higher Btu gas. Whether these customers will bear the burden of the additional cost of the high Btu gas in the field, or whether such cost will be borne by Panhandle as part of the operation of the non-jurisdictional plant depends on the method of allocation employed by the Commission in fixing Panhandle's rates. Under the method of allocation heretofore adopted for Panhandle's Tuscola operation,[15] there should be no net increase in Panhandle's jurisdictional costs by reason of the Btu adjustments.

Staff's argument that the higher Btu gas may cause pipeline operating difficulties in the form of "slugs" of condensed liquids in the line which may damage compressor equipment, or of "icing" which would cause constriction, and perhaps complete stoppage, of the flow of gas, is based on evidence which is general in nature. There is no indication that such will occur in the instant case. The record shows that Panhandle has tested and analyzed the proposed gas supplies, and its experts have testified that it can maintain efficient operations without the necessity of removing any liquids, other than water, from the gas stream prior to transporting it through its mainline system.

Thus, it does not appear that the operation of the Btu adjustment provisions in the producers' contracts will have any material adverse effect on Panhandle's jurisdictional gas service. We shall, therefore, allow the Btu adjustments subject to our determination in Docket No. R–200. Upon the establishment of a general policy with respect to such adjustments in the rule-making proceeding, the producers accepting the certificates herein issued will be required to file amended rate schedules in conformity therewith. In addition to the foregoing, we shall require, as a condition of the issuance of a certificate to Shell, that the upward Btu adjustment in its rate schedule be limited to a maximum of 1,050 Btu's rather than 1,200 Btu's as now provided in its contract. Shell's counsel stated in the oral argument before the Commission that Shell will deliver the Elk City gas to Panhandle at 1,050 Btu's per cu. ft., and it is most unlikely that this condition will have any restrictive effect on Shell's revenues. However, since the Shell gas will constitute the major portion of Panhandle's Oklahoma supply, and since our finding of no adverse impact on Panhandle's jurisdictional service is based on the delivery of 1,050-Btu gas at Elk City, this condition on the extent of Shell's upward Btu adjustment is a safeguard reasonably required in the public interest. We shall also condition Shell's certificate to require that the Btu adjustment be computed, not on the basis of the total 17.5-cent price which includes gathering, dehydration and compression, but on the basis of the equivalent wellhead price of 15 cents per Mcf.[16]

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[15] See note 12, and discussion above.

[16] As noted by the examiner, upward Btu price adjustment provisions are not unusual in contracts for the sale of gas in the western part of Oklahoma; and, prior to the issuance of Policy Statement No. 61–1, we approved such adjustments in contracts for gas sold from the Laverne field in Harper and Beaver Counties, the Enville, West Enville, and Southwest Enville fields in Love County, and the West Cement and South Rainey fields in Caddo and Washita Counties.

In the Policy Statement, at page 2, we said: "The relevance of such adjustments to the basic contract price and the appropriate established price standard must be considered as each filing is made. As it becomes apparent that certain adjustments have general

On May 2, 1961, the Commission permitted Union Oil Company of California to withdraw its application in Docket No. CI60–802. Union's withdrawal was based on the cancellation of its contract with Panhandle. On May 26, 1961, Ashland Oil & Refining Company, the applicant in Docket No. CI60–738, gave notice cancelling its contract with Panhandle. Similar action was taken by Pioneer Production Corporation, the applicant in Docket No. CI60–689, by notice dated May 29, 1961. On June 30, 1961 and July 26, 1961 the Commission permitted the withdrawal of Ashland's and Pioneer's applications.

The examiner found that the withdrawals would not significantly affect the feasibility or financing of Panhandle's proposed project; and because the new lateral will undoubtedly connect additional en route supplies to more than replace the gas lost through such withdrawals, the examiner used the volumes, estimates, and other material facts as originally presented. In his initial decision, the examiner would permit the producers who have cancelled their contracts and sought withdrawals herein to rescind their cancellations and reinstate their applications, *nunc pro tunc;* and, upon reinstatement, he would issue certificates to them on the same terms and conditions as to the other en route producers.

We agree with the examiner's approach to the treatment of the producer applicants who have cancelled their contracts with Panhandle, and shall follow his recommendation in the issuance of certificates to these producers.

The Commission further finds:

(1) Panhandle is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission.

(2) Panhandle's proposed facilities hereinabove referred to, and more fully described in its application, will be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and such facilities, together with the construction and operation thereof, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Each of the independent producers named above as parties to this proceeding is or upon initiation of the proposed sales to Panhandle will be engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission, and is or will be a "natural gas company" within the meaning of the Natural Gas Act.

(4) The sales of natural gas proposed by each of the producer applicants, as more fully described in their applications, are subject to the jurisdiction of the Commission, and such sales, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) Subject to the requirements of our order herein and the conditions of the certificates herein issued, Panhandle, and each of the producer applicants who has not withdrawn, are able and willing to properly do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder. Those producer applicants who have cancelled their contracts and sought with-

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applicability in a specific area, the area price standard will be revised and set forth in greater detail with regard to the exact sale conditions to which the rate applies."

Proposed additions to the Policy Statement which would set forth standards for pipeline quality gas, and the allowable adjustments, including Btu adjustments, for deviations from such standards, are, as hereinabove indicated, before the Commission in the R–200 rule-making proceeding.

drawals herein should be permitted to reinstate their applications, *nunc pro tunc*, within 30 days from the date of the issuance of this order, thereby indicating their ability and willingness to properly do the acts and to perform the services proposed in their original applications, and to conform to the provisions of the Act and the requirements, rules and regulations of the Commission.

(6) The construction and operation of the facilities proposed by Panhandle, and the sales proposed by each of the producer applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity, and certificates should be issued to each of them as hereinafter ordered and conditioned.

(7) The conditions attached to the certificates herein issued are required by the public convenience and necessity.

The Commission orders:

(A) Certificates of public convenience and necessity are hereby issued upon the conditions hereinafter set forth: to Panhandle Eastern Pipe Line Company for the construction and operation of the facilities proposed, as more fully described above and in its application; and to Shell Oil Company, Calvert Petroleum Company, and King-Stevenson Oil Company, Inc. for the sale of natural gas in interstate commerce for resale as proposed, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, as more fully described above and in their applications.

(B) Within 30 days from the date of the issuance of this order, Pioneer Production Corporation, Ashland Oil & Refining Company and Union Oil Company of California shall have the option to rescind the cancellation of their contracts with Panhandle and the notices of withdrawal from this proceeding, and to notify the Commission of the resubmittal of their applications on the same terms and conditions as originally applied for by them in this proceeding. In the event such resubmission is made, the applications shall be reinstated and certificates shall thereupon be issued, *nunc pro tunc*, to the producer applicants making such resubmission, authorizing the sale of natural gas in interstate commerce as proposed; subject, however, to the same conditions as hereinafter set forth with respect to the other independent producers.

(C) The certificate herein issued to Panhandle and the rights granted thereunder are conditioned upon Panhandle's compliance with all applicable Commission Regulations under the Natural Gas Act, and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) and (e) of Section 157.20 of such Regulations. The time within which Panhandle's facilities shall be constructed and placed in actual operation, as provided by paragraph (b) of Section 157.20, is hereby fixed at six months from the date of the issuance of this order.

(D) The certificate herein issued to Shell Oil Company is granted upon the express condition that Shell shall file a rate schedule with the Commission within 30 days from the date of the issuance of this order providing for a base initial price, replacing the initial contract price as proposed, not in excess of 17.5 cents per Mcf (14.65 psia), including tax reimbursement, for gas sold and delivered to Panhandle at a central point in the Elk City field, and further providing that adjustments in price for variations in Btu content above and below 1,000 Btu's per cu. ft. be computed on the basis of the equivalent wellhead price of the gas, herein found to be 15 cents per Mcf, and be limited to a maximum upward adjustment based on 1,050 Btu's per cu. ft. In all other respects said rate schedule shall conform to Shell's application.

(E) The certificates herein issued to the other producer applicants named above are granted upon the express condition that each of the applicants proposing en route sales to Panhandle in Woods, Dewey, Major and Alfalfa Counties, shall file a rate schedule with the Commission within 30 days from the date of the issuance of this order providing for a base initial wellhead price, replacing the initial contract price as proposed, not in excess of 15 cents per Mcf (14.65 psia), plus Btu adjustment, for gas sold in said counties. Said rate schedules shall in all other respects conform to the producers' applications.

(F) In the event the Commission, by amendment of Policy Statement No. 61–1, adjusts the boundary between the Panhandle area and the "Other" Oklahoma area so as to increase the initial wellhead price level for new gas in the area of the sales herein certificated, the producer applicants accepting the certificates herein issued may thereupon substitute new rates reflecting the amount of such increase, and thereafter collect these new rates prospectively in lieu of the initial rates herein required.

(G) The certificates herein issued to the producer applicants are granted upon the express condition that the allowance of the take-or-pay provisions and the upward Btu price adjustment provisions in their contracts with Panhandle is subject to our ultimate disposition with respect to such provisions in the rulemaking proceedings in Docket Nos. R–199 and R–200, respectively. Upon the establishment, by amendment to the Statement of General Policy No. 61–1, or by regulation, of general policies governing such provisions in producer contracts, the producers accepting the certificates herein issued shall file within 30 days amended rate schedules in conformity therewith, acceptable to the Commission; provided, however, that the producers shall not be required to file take-or-pay provisions for less than 80 percent of the annual contract quantities.

(H) The certificates herein issued to the producer applicants shall be accepted in writing and under oath within 30 days from the date of the issuance of this order; and the facilities authorized by said certificates shall be constructed and placed in actual operation within six months from the date of the issuance of this order.

(I) The certificates issued to the producer applicants are not transferable and shall be effective only so long as each of said applicants continues the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act, and the applicable rules, regulations and orders of the Commission.

(J) The grant of the certificates herein shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act, or of Part 154 of the Regulations thereunder. Such grant is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicants. Further, the action in this proceeding shall not foreclose nor prejudice any further proceedings or objection relating to the operation of any price or related provision in the gas purchase contracts herein involved.

(K) The certificate herein issued to Panhandle shall not become effective until acceptance by Shell of its certificate for the Elk City sale to Panhandle.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

ORDER CLARIFYING OPINION NO. 350 ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND GRANTING MOTION FOR EXTENSION OF TIME

(Issued February 5, 1962)*

On January 15, 1962, we issued Opinion No. 350 granting certificates of public convenience and necessity in the above-designated consolidated proceeding. On January 29, 1962, Shell Oil Company (Shell) filed a motion, as supplemented by a telegram of the same date, requesting clarification of certain ordering paragraphs in our Opinion as well as an extension of certain times designated therein.

Specifically, Shell requests clarification of our Opinion in respect to its applicability to the non-operator co-owners of working interests in the Elk City Field. Additionally, Shell requests an extension of the 30 days required for the filing of acceptances of the certificates granted and for the filing of a rate schedule.

Panhandle Eastern Pipe Line Company and East Ohio Gas Company by letters dated January 30, 1962 and February 1, 1962, respectively, have stated that they have no objection to the granting of the requested extension of time.

There being no opposition to Shell's motion for an extension of time, the motion is granted as hereinafter ordered. As further requested, we shall make a substitution of specified paragraphs appearing in our Opinion No. 350, as hereinafter ordered, to more fully express the intent thereof.

The Commission orders:

(A) Ordering paragraph (A) in our Opinion No. 350 is hereby deleted and the following paragraph is inserted in substitution thereof:

(A) Certificates of public convenience and necessity are hereby issued upon the conditions hereinafter set forth: to Panhandle Eastern Pipe Line Company for the construction and operation of the facilities proposed, as more fully described above and in its application; and to Calvert Petroleum Company, King-Stevenson Oil Company, Inc. and Shell Oil Company (and to all the non-operator co-owners of working interests in the Elk City Field ratifying the gas sales contract dated March 23, 1960, between Shell and Panhandle or who may hereafter authorize Shell as operator to deliver to Panhandle their interest in the Elk City Field gas pursuant to the terms and provisions of said contract, as herein conditioned) for the sale of natural gas in interstate commerce for resale as proposed, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, as more fully described above and in their applications.

(B) Ordering paragraph (D) in our Opinion No. 350 is hereby deleted and the following paragraph is inserted in substitution thereof:

(D) The certificate herein issued to Shell Oil Company and the Elk City Field non-operator co-owners of working interests referred to in ordering Paragraph (A) hereof, is granted upon the express condition that Shell shall file a rate schedule with the Commission within 40 days from the date of the issuance of this order providing for a base initial price, replacing the initial contract price as proposed, not in excess of 17.5 cents per Mcf (14.65 psia), including tax reimbursement, for gas sold and delivered to Panhandle at a central point in the Elk City Field, and further providing that adjustments

*Parties and docket numbers printed *supra* p. 35.

in price for variations in Btu content above and below 1,000 Btu's per cu. ft. be computed on the basis of the equivalent wellhead price of the gas, herein found to be 15 cents per Mcf, and be limited to a maximum upward adjustment based on 1,050 Btu's per cu. ft. In all other respects said rate schedule shall conform to Shell's application. Upon Shell making the filing required in this paragraph the non-operators in the Elk City Field shall not be required to duplicate such filing and the filing by Shell shall be deemed to be made for itself individually and for all non-operator co-owners in the Elk City Field ratifying or authorizing the delivery of their share of the Elk City Field gas pursuant to the contract of March 23, 1960, between Shell and Panhandle as conditioned herein.

(C) Ordering paragraph (H) in our Opinion is hereby deleted and the following paragraph is inserted in substitution thereof:

(H) The certificates herein issued to the producer applicants shall be accepted in writing and under oath within 40 days from the date of the issuance of this order; and the facilities authorized by said certificates shall be constructed and placed in actual operation within six months from the date of the issuance of this order.

(D) Ordering paragraph (K) in Opinion No. 350 is redesignated as paragraph (L).

(E) The following paragraph is inserted in our Opinion No. 350 as paragraph (K).

(K) As to Elk City Field which has been unitized, with Shell as Unit Operator, the certificate herein issued to Shell, subject to the rights granted thereunder and the conditions attached thereto, shall apply not only to Shell individually but also to Shell as Operator of the Elk City Unit for and in behalf of the non-operator co-owners of working interests in said Unit ratifying or adopting the gas sales contract dated March 23, 1960, between Shell and Panhandle and accepting this certificate within the time specified in paragraph (H) hereof, as well as each non-operator co-owner of a working interest in the Elk City Unit who may hereafter authorize Shell as operator to deliver to Panhandle his interest in the Elk City Field gas pursuant to the terms and provisions of the contract dated March 23, 1960, between Shell and Panhandle, as herein conditioned.

DECISION

UPON APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued July 11, 1961)

WESTON, *Presiding Examiner:* In this proceeding, Panhandle seeks authority to build a new 200-mile supply lateral southwesterly from its Haven compressor station in Kansas to connect with Shell's Elk City gas field in western Oklahoma. Shell and the other producers seek authority to sell the gas to be picked up by the proposed new lateral.

The important issue is whether the initial price for the gas (including "fringe benefits" to the producers), as carefully and providently negotiated by the parties is consonant with the public interest protected by the Commission. The gas is uniquely valuable and needed, but the price to Panhandle is high, and is out-of-line in a general sense. After some months of study, two relatively simple points about the "initial price" problem become clear, and should be kept in mind as this decision is read: (1) language in judicial decisions, as Judge Brown of the Fifth Circuit has well shown (see *infra*), is of little or no help in the solution of a case like the one at bar; (2) rulings in specific cases, on the important and

evolving subject of initial price regulation, must follow the general lines of Commission policy expressed in general orders, rather than attempt to effect new departures in such policy.

DESCRIPTION OF THE PROJECT

I. *The Basic Project: Panhandle-Shell.* The feasibility of the lateral depends on supply from Shell's Elk City field. The other producers would supply relatively minor "enroute" deliveries from fields along the proposed lateral line; the deliveries now contracted for are only indicative of ultimate future connections, as new conveniently located gas is discovered.

A. *Panhandle's Situation, In General.* Panhandle, one of the largest pipelines in the country, supplies gas principally to distribution companies located in Texas, Kansas, Missouri, Illinois, Indiana, Michigan, and Ohio. Most of the gas comes from the southwestern part of its system under gas purchase contracts with producers in Texas, Oklahoma, and Kansas; other gas comes from Panhandle's own production. In the past Panhandle has been removing more than 300,000,000 Mcf per annum from its southwestern sources.

To meet demand, Panhandle has had to resort to extraordinary measures. It has obtained 80,573,000 Mcf from other pipelines on temporary short-term supply contracts. It has overproduced (*i.e.* under State conservation allowables) its own gas resources by 85,395,000 Mcf as of January 1, 1960.[1] In July 1959 Panhandle was authorized to discontinue delivery of 46,355,000 Mcf annual supply to Michigan Consolidated Gas Company, and to redistribute this volume among Panhandle's resale (*i.e.*, distribution company) customers, because of the latter's critical needs. See *American Louisiana Pipe Line Co.*, 20 FPC 851; 21 FPC 218; 22 FPC 82.[2]

To Panhandle, as to any pipeline, replacement of gas and maintenance of reserves is, of course, a necessity. During the five-year period January 1, 1955, to January 1, 1960, Panhandle entered into an aggregate of 162 gas purchase contracts connecting aggregate reserves of 607,125,000 Mcf. When annualized, such acquisitions do not begin to meet Panhandle's market. Panhandle's existing customers take about 410,000,000 Mcf per year, but need, and are anxious to purchase, more than 483,000,000 Mcf per year—an unsatisfied market of about 75,000,000 Mcf per year. Panhandle's most recent expansion program was based on new deliveries instituted under temporary certificates issued in 1954 and 1955, permanently authorized in *Panhandle Eastern Pipe Line Co.*, 15 FPC 46. Panhandle has currently pending before the Commission a proposal for major sales expansion (Docket CP60–60), for which the gas supply involved in this proceeding is a basic necessity.

Further findings centered on Panhandle's needs and the value of this gas to Panhandle and its customers are detailed later herein.

B. *Shell's Situation, In General.* Shell is the 75 percent owner of, and operator of, the unitized Elk City field, mostly located in Beckham County (balance in Washita County) of western Oklahoma. The field was discovered in 1947. It was unitized in 1950 by order of the Oklahoma Corporation Commission for the production of oil, condensates, and gas, and has since been operated, for maximum recovery of liquids, by cycling and reinjection of gas as produced with the liquids. Currently, operation of the field for recovery of liquids has become marginal, recycling has diminished liquids to the point that Elk City should be

[1] Possibly to be retroactively increased by 12,000,000 Mcf, depending on validity of a Kansas Corporation Commission order which liberalized Panhandle's allowables.

[2] The Commission's order was reversed and remanded, *Michigan Consolidated Gas Co. v. F.P.C.*, 282 F. 2d 854; 283 F. 2d 204 (CADC), and hearings are currently in progress on Michigan Consolidated's demand for restoration of the 46,355,000 Mcf per annum.

operated as a gas field, and recycling is scheduled to be discontinued at the end of 1963.

The field extends over some 11,800 acres. It contains nine separate producing reservoirs at depths between 8,950 and 10,900 feet, tapped by 295 wells. Because of the long cycling history, reserves can be estimated with great accuracy. Reserves in place total 807,893,000 Mcf, of which 746,316,000 Mcf are recoverable. After allowance for shrinkage and fuel, 701,536,000 Mcf will be available for use and sale in Panhandle's system. This one "package" of gas is considerably larger than all of Panhandle's acquisitions in 162 separate purchases in the 1955–1960 five year period, *supra*.

Under the contract, Panhandle would deplete the Elk City field in 15 years, beginning with withdrawals of 45,625,000 Mcf in 1961, continuing with 49,275,000 Mcf in 1962 and 1963, and at a predominate rate of 46,611,000 Mcf in subsequent years. The "early depletion of the field * * * in 15 years instead of 20 or 22" was a main consideration moving Shell to close with Panhandle rather than with other bidders. (Tr. 43, 66–67.)

The deliverability capacity of the field is unusually high. Shell must furnish Panhandle, at the latter's 5-year option, up to 225,000 Mcf per day on a continuous basis, and Panhandle has other options down to a floor of 125,000 Mcf per day.

Shell decided to sell its Elk City gas in October 1958, and received three firm offers for an "in place" sale[3] and six firm offers from pipelines (including Panhandle) for a conventional per-Mcf sale. All of the other pipeline offers (El Paso, Northern, Natural Gas Pipeline, Michigan Wisconsin, and Transwestern) involved initial prices[4] and total prices (after future escalations) substantially higher than Panhandle's offer, but contemplated depletion of the field over a 20-year period.

Shell's facilities at Elk City include gathering lines, well equipment, a processing plant for removal of liquids, and reinjection equipment. Direct cost of the wells and surface facilities (excluding cost of leases and other costs termed "indirect" in the industry) has been about $75 million. Under the contract, Shell will supply Panhandle with pipeline quality gas at the tailgate of the processing plant, and Shell will spend between $200,000 and $300,000 immediately for dehydration equipment. Under the contract, Shall agrees to continuously deliver the gas at the high minimum pressure of 825 psig (maximum 875 psig), and over the life of the contract will have to spend some $6 million for changes in the gathering system and compressors, and for additional compression.

In the Oklahoma-Texas area, it is highly unusual, if not unprecedented, for a producer to undertake the quality, pressure, and delivery features of Shell's agreement in this case. Most gas in the area is picked up at the wellhead by the pipelines. The pipelines provide and operate all processing and gathering facilities. Panhandle is advantaged in respect of jurisdictional revenues and expenses, consequently its customers and the ultimate consumers are equally advantaged, to a substantial dollar amount, not susceptible of exact computation, by Shell's present and future facilities, and Shell's future services, in respect of the Elk City deliveries.

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[3] *I.e.*, direct sale of the total block of the gas for a single cash consideration, payable in installments. These offers are "still outstanding, and they are kind of confidential in the sense that we might want to take advantage of them." (Tr. 42.) Considering the size of the reserves, it may be assumed that the offers involve interstate transportation to the point of consumption of the gas, and consequently would require Commission approval, including consideration of price. See *F.P.C. v. Transcontinental Gas Corp.*, 365 U.S. 1; cf. *P.S.C. of N.Y. v. F.P.C.*, 287 F. 2d 143 (CADC).

[4] Because of the Commission's power to suspend and disallow escalations, initial price is the significant fact.

C. *Jurisdictional Facilities and Feasibility.* On account of the Elk City connection (incidental connections, *infra*), Panhandle will lay 50 miles of 22-inch and 150 miles of 24-inch high pressure pipe with valves and fittings. No compression will be needed, because Shell will through the life of the contract supply the gas at high pressure.[5] Fully powered, the line will carry volumes up to 340,000 Mcf per day, compared to Shell's possible maximum deliveries of 225,000 Mcf per day.[6] The cost will be approximately $15.7 million, easily financed by Panhandle out of cash on hand and short term bank loans already committed. All preliminary right-of-way engineering, and other details have been completed, and the lateral can be installed and operating in about three months, or in time for the 1961–1962 winter heating season.

With respect to feasibility, it is clear that, even without needed expansion of Panhandle's deliveries, the addition of the line will be economically sound. As we have seen, Panhandle has had to depend on over-production and "spot" purchases to meet its existing loads. Panhandle can take the full Elk City lateral supply without incurring any take-or-pay-for penalties. Although there may be some "cutback" of Panhandle's takes from existing connections, this "cutback" will be beneficial rather than detrimental, because of past overproduction. Out of the proposed new facilities Panhandle will realize operating revenues of approximately $10 million. After deduction of operating expenses, including slight increases in average cost of gas purchased, Panhandle will realize an average of between 2.29 cents and 2.75 cents per Mcf in operating revenue during the first three years of operation, based on existing Panhandle rates and sales contracts. The total impact of the new supply on Panhandle's cost of gas will be a *de minimis* increase of about one-tenth of one cent per Mcf. Certification of the sales here involved will not cause Panhandle to seek a rate increase. (Tr. 640.) In this and other connections, it is noteworthy that no customers or regulatory authorities oppose the project.

It is concluded that the facilities to be installed are soundly engineered and financed, and that economic feasibility, not seriously controverted, is clear.

D. *Contract Provisions In Issue.* The principal question for determination is the proposed initial price of 20.5 cents per Mcf agreed on between Shell and Panhandle for the Elk City gas, and set out in Article VIII–1–(A) of the purchase contract. Staff contends that the price should be conditioned to 15 cents per Mcf. This issue must be considered primarily in the light of *Atlantic Refining Co.* v. *P.S.C. of N.Y.*, 360 U.S. 378 (commonly known as "Catco"), and the Commission's Statement of General Policy No. 61–1, 24 FPC 818, 25 F.R., 9578, issued September 28, 1960, during the pendency of hearings herein (hereafter referred to as "Policy Statement 61–1"). The scope and application of these authorities to the facts at hand, however, is a matter for expert judgment, not "arithmetical comparison of two prices," taking into consideration the prevailing realities of producer price regulation and the practical consequences of given Commission action. Cf. Brown, J., dissenting in *United Gas Imp. Co.* v. *F.P.C.*, 290 F. 2d 133 (CA5, February 22, 1961), slip opinion, p. 17. *Cert.* den. *sub. nom. Sun Oil Co.* v. *UGI*, 368 U.S. 823.

A group of ancillary questions are presented:

1. *Btu Adjustment.* The contract provides for a Btu adjustment to the 20.5-cent price for heating values above or below the conventional industry standard of 1,000 Btu per Mcf of gas, within a range of a floor, 985 Btu (at which point Panhandle may reject the gas), and a ceiling of 1,200 Btu (no adjustment for any heating value in excess). The adjustment factor is the actual Btu content

[5] Compression will be added later to take care of new "enroute" gas picked up.
[6] The difference will come from "enroute" connections.

divided by 1,000. The Elk City gas will actually have an estimated Btu content of 1,050. Shell's actual realization, counting Btu adjustment, will therefore amount to 21.525 cents; the ceiling which Shell could realize is 24.6 cents. Staff contends that the Btu adjustment provision should be eliminated.

2. *Rate of Take.* Minimum required "take" by Panhandle under the Shell contract is as follows:

First, fourth, and fifth years—annual volume equal to average daily volume of 125,000 Mcf. Second and third years—annual volume equal to average daily volume of 135,000 Mcf. Sixth and subsequent years, 1,000 Mcf per day for each 3,650,000 Mcf of remaining reserves, "it being the intent hereof that all economically recoverable gas from contract acreage be fully depleted in the first 15 contract years." [Art. V–1(A).]

Staff contends that rate of take should be changed to reflect annual deliveries not greater than one Mcf per day for each 8,000 Mcf of recoverable reserves. This would result in a contract life, to exhaustion of the field, of approximately 22 years.

3. *Take-or-pay-for.* Under the contract, Panhandle must in each year either actually take or else pay for all of the minimum annual volumes above specified; provided, that Panhandle may during the three succeeding years take down the amount of any such paid-for deficiency for any given year without further cost. [Art. V–4(B).] However, as we have seen, Panhandle has an option to increase the delivery rate. If Panhandle thus increases contract quantities to 125 percent of contract quantities, the take-or-pay-for would automatically become 80 percent. Staff contends that, to the revised rate of take suggested by Staff, item 2 *supra*, the take-or-pay-for provision should be reduced to 80 percent.

II. *The Enroute Connections.* Along the route of the 200-mile Haven Station-Elk City lateral lie the extensive existing and potential gas producing areas of northern Oklahoma and southern Kansas. As originally presented, Panhandle had five contracts, all in identical standard form, for enroute deliveries from Oklahoma fields, as follows:

Producer	Mcf of proven reserves	Field	County location, proven reserves	Initial price
				Cents
Union	17,691,000	W. Putnam	Dewey	0.17
King-Stevenson	3,880,000	NE. Seiling and Unnamed-Dewey	Major and Dewey	.17
Ashland	21,709,000	W. Chester and NE. Seiling	Woodward and Major	.17
Continental [1]	548,000	NE. Seiling	Major	.17
Calvert	2,003,000	Avard and Unnamed-Dewey	Woods and Dewey	.17
Pioneer	11,529,000	W. Chester	Woodward	.17

[1] Continental is a "carried interest." Its acreage is properly attributable, in unstated portions, to the other producers who applied herein.

Acreage covered by these five contracts substantially exceeds proven acreage. Through exploration and development, further proven reserves are to be confidently expected.

Producer	Dedicated acreage	Proven
Union	40,192	2,800
King-Stevenson	4,918	662
Pioneer	1,856	960
Calvert	6,286	547
Ashland	7,180	2,145

On May 2, 1961, Union's withdrawal of its application in Docket No. CI60-802, based on cancellation of its contract with Panhandle, was permitted to become effective. By notice of May 26, 1961, to Panhandle, Ashland cancelled its contract with Panhandle, and Pioneer has taken the same action by notice dated May 29, 1961. The Commission has not acted on the last two withdrawals.

These withdrawals do not significantly affect the feasibility or financial details of the project. Because of this fact, and because the lateral, if constructed, will unquestionably connect replacement deliveries and more, probably at the original price and on similar conditions, the volumes, estimates, and other material facts as originally presented are used in this decision.

A. *Contractual Arrangements and Issues.* As is conventional in the area, the enroute sales are to be at the wellhead, with all facilities installed by Panhandle. Panhandle's costs in this regard, covering the five connections originally contemplated, were estimated at $987,000.

The contracts, in identical form, as noted above, all provide for a 17 cents per Mcf price. Staff presents the same issues concerning these contracts as in the case of the Shell contract, as follows:

1. *Initial Price*—Except in the case of Pioneer, whose price is not questioned, Staff contends for 15 cents rather than 17 cents.

2. *Btu Adjustment*—Staff contends that the provision should be eliminated. In this connection, it is noted that the estimates of actual Btu content from the enroute producing fields are as follows: Avard and Unnamed-Dewey, 1,000; W. Chester, 1010; NE. Seiling (Mussellem) 1,100, (Chester) 1,108. On this basis, consecutive actual per Mcf realization for the same producing fields would amount to 17.0 cents, 17.17 cents, and 18.70 cents.

3. *Rate of Take*—The contracts call for depletion of the fields over a 20-year term (life index). One-tenth of the reserves is to be depleted in each of the first two years. The remaining 80 percent is to be depleted during the succeeding 18-year period, or at approximately 4.44 percent per year, with exact volumes dependent on pressure drop as actually experienced. Overall rate-of-take balances out to amount to the purchase by Panhandle of one Mcf per day for each 7.300 Mcf of recoverable reserves in the separate fields. Staff contends that rate of take should be required to be adjusted to one Mcf per day for each 8,000 Mcf of recoverable reserves, or a 22-year life index.

4. *Take-or-pay-for*—Staff contends that the provision, essentially the same as that described above for the Shell contract, should be revised to reduce the amount to an 80 percent required take of the annual contract quantities.

Pricing-Area Considerations

As we have seen, Staff contends that the Commission should offer Shell and the other producers (except Pioneer) certificates conditioned on a 15-cents per Mcf price, rather than the price as negotiated. It is appropriate at this point to consider the factual derivation of Staff's price.

Staff's price derives from Policy Statement 61–1, with attached Press Release, which is a compendium of geographically defined gas producing areas of the United States. The areas of, and adjacent to, the sales proposed in this proceeding are divided by county lines in Oklahoma, and by Railroad Commission Districts in Texas. To each geographical area a "price level" is stated. The Policy Statement says that the Commission in arriving at such price levels, "considered all of the relevant facts available to us." It also says that:

> For the present, and in the absence of compelling evidence calling for other action by us, proposed initial sales of natural gas by independent producers which include rates [i.e., proposed prices] higher than those

> indicated in the appendix attached to this statement shall be denied a certificate or certificated only upon the condition that lower rates be filed * * *.

Policy Statement 61–1 is thus a factual *datum* bearing on the disposition of this case, and we must consider the location of the new sales here proposed in relation to the areas and price levels there set out.

As we have seen, the Elk City field lies mostly in Beckham County, and partly in Washita County, which bounds Beckham to the east. The enroute connections as originally proposed involve fields to the northeast, in the contiguous counties of Woodward, Woods, Alfalfa, Major, and Dewey.

Policy Statement 61–1 sets up three pricing areas in Oklahoma:

1. *Panhandle Area*—Cimarron, Texas, Beaver, Harper, Woodward and Ellis Counties, which form a contiguous group of counties in northeast Oklahoma. The level of initial price for new service, "for the purpose of guidance and initial action by the Commission," is set at 17 cents per Mcf.

2. *Carter-Knox Area*—a portion of Grady and Stephens Counties known as the Knox Field, lying in the geological formations below the base of the Pennsylvania Series. Grady and Stephens Counties lie in the southwest-central portion of Oklahoma. The price level is set at 16.8 cents per Mcf.

3. *"Other" Area*—all Oklahoma except the two areas above-described. The level is 15 cents per Mcf.

Beckham County, the site of the Elk City connection, is bounded on the north by Ellis, one of the Panhandle area counties. Beckham is bounded on the west by two of the twenty-six contiguous north Texas counties which comprise the large area of Railroad Commission District No. 10, for which the Policy Statement prescribes a 17-cent price. However, Beckham County, not being part of the Panhandle or Carter-Knox, is assigned the 15-cent price stated for "Oklahoma-Other." The counties along the route of the lateral are also in the "Oklahoma-Other" area, except for Woodward County, which is included in the Panhandle."

It appears that Pioneer's connection is in Woodward County, and Staff, construing the Policy Statement as a rigid and unchangeable set of price ceilings, contends for:

> An initial service rate of 15.0 cents per Mcf for all producers herein, exclusive of Pioneer. Pioneer should be certificated at the requested intial service rate of 17.0 cents per Mcf. (Br. 44.)

I. *Construction of Policy Statement 61–1.* However, it is clear enough, *a priori*, that the Commission intended changes in ceilings and in the boundaries of areas, as well as the creation of new areas, in accordance with the facts and public interest as found in specific proceedings such as the instant case.[7] The Commission said in the Policy Statement:

> * * * The geographical areas which we have used are convenient and well known. They are not necessarily in complete accord with geographical and economic factors which may be relevant to the establishment of pricing areas. As experience and changing factors may indicate we will change or alter these areas from time to time in order to eliminate such inequities as may appear to exist because of our use of geographical boundaries.

This construction of the Policy Statement is required as a matter of law, for the Natural Gas Act itself provides for notice, hearings, and findings with regard to the public convenience and necessity of specific applications. Act,

[7] As well as in "area hearings," also contemplated by the Statement.

sec. 7 (c), (d), and (e). Policy Statement 61–1 was issued without notice, hearings, or public record. The Commission cannot legally, and therefore should not be considered to have attempted to, determine without notice or hearing the convenient and necessary price applicable to the Elk City and enroute sales. Consequently, Staff's broad contention that the price issue is disposed of by Policy Statement 61–1 is disallowed without further analysis. Policy Statement 61–1, so far as presently pertinent, is an *approach* toward definition of the price "line" mentioned in *Catco* (360 U.S. at 391), not a *determination* of that line.

It also seems clear enough, simply from looking at the map of Oklahoma and north Texas pricing areas, that the specific "Oklahoma-Other" area, whence most of the gas here involved comes, was created as a temporary catch-all, intended to be the subject of refinement, further definition, and further delineation, according to the facts and public interest as found in particular proceedings before the Commission. The Statement, in its opening paragraph, characterizes its utility as that of "a guide to us and to interested parties;" *i.e.*, suggestive rather than determinative.[8]

So construed, the Policy Statement (a) gives scope for the basic natural facts of geology, market area history, and oil and gas economics as adduced in specific cases in connection with pricing new gas supply; (b) does not establish arbitrary pricing zones, contrary to specific evidence, based on county or other artificial geographical lines; (c) is not a final order subject to review. See *Wisconsin* v. *F.P.C.*, 292 F. 2d 753 (CADC, decided May 18, 1961).[9] So construed, the Policy Statement is for present purposes a statistical compilation (confirmed by price statistics presented in this record by a Staff witness) and no more.

II. *Geological and Other Factors.* The entire upper Oklahoma gas producing area lies in the Anandarko Basin, and constitutes a single geological province. In general, the producing horizons therein trend downward, *i.e.*, to greater depths, from the Colorado border southeasterly to Woodward County, Oklahoma. The productive formations from which the gas involved in this proceeding is derived (*e.g.*, Chester, Mussellem, and Tonkawa) are common to the entire Panhandle area (as commonly known) of Texas and Oklahoma, and are related or identical in all parts of the area in respect of age, lithology, and physical characteristics.

In respect of marketing area, geography, and well-drilling and operating attributes, the Elk City and enroute connections are like the conditions encountered in the Laverne Field of Harper County, Oklahoma (*i.e.*, in the Panhandle area), except that Laverne is shallower, consequently less expensive to drill and operate.[10] For the Elk City and other formations here involved, drilling depths are as follows:

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[8] It may well be that Policy Statement 61–1, insofar as presently relevant, is intended only as a publication of the theretofore undisclosed standards by which the Commission had previously determined whether or not to hold full hearings on proposed new connections, rather than shortened procedures under Sec. 1.32 of the Rules of Practice and Procedure.

[9] In the cited case, the decision dismissing the appeal was grounded on Wisconsin's lack of status as a "party to a proceeding" before the Commission, citing *United Gas Pipe Line Co.* v. *F.P.C.*, 181 F. 2d 796, cert. denied, 340 U.S. 827. As construed, the Policy Statement does not "aggrieve" producers or others, thus is not appealable on more conventional grounds.

[10] Costs actually incurred in the NE. Seiling and Unnamed-Dewey fields are 20 percent greater than costs in some of the deepest portions of Laverne.

Field	County	Depth
Avard	Woods	4,895
W. Chester	Woodward	7,977
NE. Seiling	Major	8,400
Unnamed	Dewey	8,885
W. Putnam	Dewey	10,500
Elk City	Beckham	8,950–10,900

Production in the Oklahoma Panhandle derives from the Mississippian and Pennsylvanian formations, which continue into the western Oklahoma area of the present proposed sales. More gas is expected to be discovered at deeper levels in western Oklahoma when exploration is continued. From a geological standpoint, there is no reason to differentiate between (a) the Panhandle (six county) and north Texas pricing areas now assigned a 17-cent initial price, and (b) the area of the Elk City and enroute sales, now assigned a 15-cent initial price.

Assuming a firm Commission policy to give producers an extra price incentive to "encourage and enable producers to explore for and develop gas from these deeper formations," *Phillips Pet. Co.*, 22 FPC 528, 529, it is clear that any distinction between the Panhandle area and the area of the present sales should reflect higher prices, rather than lower, for the latter area.[11]

From the standpoint of marketing or "shopping," areas, there is no basis for distinguishing the area of the Oklahoma Panhandle (17-cent price) or the upper portion of Texas R.R. Commission District No. 10 (17-cent price) from the contiguous or one-county removed areas of Beckham, Washita, Woodward, Dewey, Major, Ellis, and Alfalfa Counties, from which the Elk City and enroute deliveries are proposed in the case at bar. The entire area is a part of, or on the periphery of the territory known as "pipeline alley," whence many of our nation's largest pipelines have, since commencement of large scale natural gas operations, drawn a major part of their gas supplies. The commonly used point of reference for the sales herein, and neighboring sales, is the Anandarko Basin.

Alternative Supply

If Panhandle is unable to connect the gas involved in this proceeding, the testimony is that it will have to institute an intensive purchasing program from sources as nearly as possible adjacent to its main southwesterly pipeline. Panhandle has made studies looking towards such a program, which would involve extensive new drilling by producers in Beaver and Harper Counties, Oklahoma, and in Clark County, Kansas.

Producers in this area conventionally sell gas at the wellhead; in the words of an experienced oil man, "it is a rare thing if a producer builds a foot of pipeline" (Tr. 214). Therefore, to connect the alternative gas, Panhandle would have to build an extensive new gathering system, and new mainline facilities, connecting an estimated 233 wells, to replace the Elk City lateral supply. Estimated first year costs for the whole program would amount to over $26 million, with additional costs in future years of some $6,750,000.[12]

If we consider only the facilities required to gather and treat the hypothetical alternative gas, Panhandle would have to spend about $6 million, at a first year

[11] There is considerable testimony in the record specifically showing that drilling costs are higher in the area here involved than in areas of 17-cent Commission-allowed prices. However, such evidence is not, and cannot be, meaningfully stated in the form of dollars and cents allowances for extra costs.

[12] For comparison, total Panhandle expense for gathering, dehydrating, and field compression of gas obtained from January 1, 1955, to January 1, 1960, was $12,411,600.

cost of service of some $2.5 million, or 5.03 cents per Mcf. Panhandle's actual cost of gathering recently acquired gas amounts to 3.98 cents Mcf. In both cases, for purposes of comparison with the case at bar, in which Shell will maintain at least 825 pounds of pressure full term, future compression must be added by Panhandle to offset pressure decline; Panhandle's current field compression costs about one cent per Mcf.

In summary, it may be said that considering the alternative presented, Panhandle is advantaged to the extent of five to six cents per Mcf by Shell's gathering compression and dehydration services at Elk City.

In *El Paso Natural Gas Co.*, 23 FPC 369, 376, rehearing denied, 23 FPC 610, the Commission adjusted Aneth Field prices to compare with San Juan Basin prices by adding "some 5 cents per Mcf representing processing and related costs" otherwise payable by the pipeline for prime supply. See also, *J. M. Huber Corp.*, 22 FPC, 338, 340, which in effect allows 2 cents per Mcf for pressurizing to 250 pounds and 2.71 cents per Mcf for gathering the gas. However, this is not an acceptable method or basis for upward adjustment of prevailing prices generally, or in the case at bar.

"Alternative supply," as presented here, is a purely hypothetical, conjectural, imaginary project useful only to make an argument in support of the Elk City and enroute prices. An infinite variety of other projects, or infinite variations on the stated project, could as well be conceived and presented in the record. If Elk City is not connected and the stated alternative does not materialize (much of the contemplated alternative acreage is not available, being contracted for by other pipelines), then Panhandle might incur even greater costs to connect gas from more distant sources. Proponents of low prices could, as well, imagine new discoveries of dry gas comparable in volume to Elk City, and even more conveniently located to Panhandle, as possible "alternatives" arising from the extensive new drilling program envisaged by the argument. Speculation of this character could be endless, and fruitless in the resolution of actual prices for actual new gas supply.

The argument does, however, bring to light a fundamental problem—whether the price issue is to be determined from the point of view of the producer—what the producer receives—or the pipeline—what the pipeline pays. There is a very real difference when the unstated premise for the point of view is one or another aspect of cost. Thus, in some cases depth of drilling—a cost related factor—is used to explain current producer price levels. In other cases, such as Shell's Elk City situation, costs may have already been completely returned, and realizations may be excessive or inordinate on public utility "cost" concepts.

As will be shown *infra*, the fact that the producer receives excessive return is not material on the currently applicable premises that "value" and "area price" of gas are the important standards. The consumer is, for the present, adequately protected if "the price is right" so far as the pipeline is concerned.

Value, Cost, and Need

The clear indications from the facts so far recited are that in terms of *value* to gas-hungry pipelines Elk City is a highly desirable property. Let it be perfectly clear that, because of size of reserves, certainly of reserve estimates, flexibility of deliveries to meet Panhandle's changing needs ("swing"), high pressure, pipeline quality, single point delivery, and location and accessibility of supply, the Elk City gas is, in the words of Panhandle's consultant, "the most desirable single source of supply of gas available in the United States today" (Tr. 195).

Let it also be perfectly clear that the terms of the Shell-Panhandle contract reflect *value of gas*, not price control on cost or other standards. Part of this value is reflected in the "early depletion" provisions of the contract; the other fringe benefits (Btu adjustment and take-or-pay-for) are also part of the consideration moving to Shell. Panhandle's situation is such that the price can be stated at 20.5 cents per Mcf, with early realization of all gas value by Shell. There is a clear inference that the fact of regulation powerfully motivated this deal on Shell's "minimum terms" (Tr. 60) as one most likely to be accepted by the Commission (Tr. 50–51, 67). The matter of Shell's alternatives to the acceptance of price conditions will be discussed *infra*; we may anticipate to say that at the present stage in the evolution of producer regulation, the Commission is in no position to apply rigid price reduction standards to transactions like Elk City without risking serious impairment of gas supply, at least for a perod of time measured in years.[13]

With regard to the enroute supply, the *values* for gas to be picked up on the Elk City lateral are at least equivalent to the values which have been translated into existing prices elsewhere in the Anandarko Basin, particularly in the Texas and Oklahoma Panhandles.

Coming to the matter of Panhandle's *need for gas*, it is crystal clear that such need is (as recited in the basic Shell contract) "critical," and immediate, for the supply of existing customers. These customers, mainly midwestern distribution companies, have been deprived of the opportunity to expand their gas sales—and opportunity which has been afforded to, and availed of by, customers located elsewhere and served by other pipelines. The failure of the project here considered would mean the collapse of Panhandle's program in Docket No. CP60–60, to the discriminatory disadvantage of consumers in its territory.

With regard to *cost of gas* to Shell and the enroute producers, there is no evidence in the present record to support even a horseback estimate. Figures indicating the reasonableness of the Panhandle-producer contract prices measured on traditional public utility standards of producer cost-of-service including return are not presented. Proceeds to the producers from their contracts with Panhandle may or may not result in inordinate profits. In this connection, note that as to Shell:

(a) The Elk City field was unitized in 1950, with well spacing, subsequent operation, and use of associated gas exclusively for the maximum production of liquid hydrocarbons. Only now, as the recoverable liquids are nearly exhausted, will the field be dedicated to gas production for sale. There is no evidence as to capital recovery or profitableness of the liquid hydrocarbon operation.

(b) The sizable gathering and processing facilities at Elk City were not bought or installed for the production of pipeline-quality gas, but for the recovery of liquids at a profit. The $75 million of costs associated with such facilities are not a factor in deciding initial gas prices here, for there s no claim of a rate base for gas service, and none exists.

(c) The only producer investment directly associated with the commencement of Elk City sales will be for dehydration equipment, and will amount to between $200,000 and $300,000. In future years, delivery at the contract pressure of 825 psig will require additional compression, which may cost the producers in the neighborhood of $6 million.

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[13] The Commission faces, rather than "abdicates," its responsibilities by considering and timing the assumption of the risk that price conditions will cause transactions for new gas to "collapse." Cf., *contra, P.S.C. of New York* v. *F.P.C.*, 287 F. 2d 143, 145 (CADC).

Weight to be given to value, cost, and need. Summing up—Panhandle is financially advantaged by Shell's agreement to supply the entire Elk City reserves in the form of pipeline quality gas at a central point and at a constant high pressure during the life of the field. Consistent with industry practice, Panhandle would have to incur substantial outlay in the form of capital investment and operating expenses to obtain equivalent gas from other sources in the area. The value of the Shell services to Panhandle in this regard is between five and six cents per Mcf.

On the other hand, the record does not show that Shell is financially disadvantaged to the same extent or degree. The principal facilities—the gathering lines and the processing plant—have long ago been installed by Shell, not for the purpose of creating an attractive gas purchase deal, but for the purpose of extracting liquids and reinjecting gas to maintain reservoir pressures. To an unknown extent, Shell has already recovered all of its Elk City capital and operating expenses through sales of liquids, and has perhaps made substantial profits on operations to date, after amortization of all investment. If we focus on the Shell situation, there is no showing that Shell is not, in terms of cost and financial needs (whether measured by conventional utility conceptions or industry economics), receiving windfall returns from the projected gas sales at 20.5 cents.

In this situation, it is concluded that for purposes of Section 7 certifications, the "price line" is to be measured by the comparative prices of given gas purchases to the pipeline, after giving effect to any applicable discounts for costs otherwise borne by the pipeline on account of, for instance, services such as Shell will perform in the case at bar. Panhandle's savings are *jurisdictional* in that they lower and are directly reflected in Panhandle's regulated rates. The savings accrue directly to Panhandle's customers in the form of lower rates prescribed in the FPC tariffs. Panhandle's distribution customers, in turn, effect savings which are directly beneficial to the ultimate customers. In a proximate sense, consumers are not prejudiced by even inordinate profits to Shell, so long as the outlay by the pipeline for connecting the new reserve is not excessive.[14]

Therefore, the Elk City transaction is to be viewed as one in which Panhandle is paying about 15 cents per Mcf for gas, and about 5–6 cents per Mcf, plus fringe benefits, for the value of its savings in capital and operating outlay for wellhead connections in the area.

Towards a Rationale of Initial Prices Consonant With the Public Interest

We may start by confirming that, as the title of this section indicates, we are today, seven years after *Phillips* and two years after *Catco*, still without a clear formula for determining the price issue for new gas connections. We are working *towards* a rationale of initial prices in Policy Statement 61–1; we have not arrived at final conclusions. The case at bar brings into focus all of the important considerations involved in the evolution of pricing policy—the principles, mostly economic, for price determination, the practical consequences of the adoption of given pricing principles, and the bearing of court and Commission authorities on this case.

I. Principles of Pricing. Since the authorities have not yet done so, it is time to set down a synthesis and evaluation of the known methods which might be applied in fixing producer prices for new gas:

1. *Cost-of-service. Catco* and other authorities reiterate a general distinction between the kind of proof necesary in a proceeding to determine fair and rea-

[14] "As Shell is, no doubt, well aware, after connection of the gas it will be subject to whatever rate regulatory control that may evolve in the future, with regard to the limitation of its profits from the Elk City supply.

sonable rates under Sections 4(e) and 5(a) of the Act (rate cases), and the kind of proof necessary in the determination of an acceptable initial price under Section 7 of the Act (certificate cases). There is a verbal distinction, of course; Section 7 does not specify "fair and reasonable" initial prices for producer certifications.

The distinction, which the cases seem to make one of *quantum* of proof, does not apply to pipelines and other utilities regulated by this Commission. Pipelines must present showings, as to new service, of the effects thereof on costs and return. Regulations Under the Natural Gas Act, Sec. 157.14(a) (16) and (18). If producers were regulated as conventional utilities, costs would be considered in the derivation of their initial rates, for the "fair and reasonable" conception or something closely akin thereto, under *Catco*, and subsequent judicial authorities (*infra*) inheres in the initial price issue, as it does in the rate increase issue. Thus, the *desideratum* in both cases is consumer potection, *i.e.*, in a general sense, no exorbitant prices; the distinction between proof of fair and reasonable rates under Sections 4(e) and 5(a) and the "lowest possible reasonable rate consistent with the maintenance of adequate service" [25] is a distinction only of degree.

The People and Public Utilities Commission of California continue to press the need for "relevant cost evidence" in certificate cases. Brief in *Standard Oil Co. of California*, Dkt. No. C160–333 *et al.*, pending, p. 23; brief and indications from the opinion in *Texaco Inc.* v. *F.P.C.*, 290 F. 2d 149 (CA5, decided April 14, 1961). The Commission Staff has not abandoned the contention that some cost evidence should be presented. (Br. herein, pp. 16–18.) Evidence as to the producers' costs "might or should appropriately be adduced in justification of the proposed price" in some cases, according to *El Paso Nat. Gas Co.*, 23 FPC 369, 375 (ftn. 13), and cost evidence "may well be relevant in some situations in determining a proper producer initial price" according to the order on rehearing, 23 FPC 610, 612–613.

However, it is clear that the Commission has not grounded its principal recent decisions on conventional cost-of-service considerations, and has flatly ruled such considerations immaterial even in rate proceedings. Order of April 5, 1961, in Area Rate Proceeding AR61–1; Policy Statement 61–1; *Phillips Petroleum Co.*, 24 FPC 537, 547.

As a practical matter, at the present stage in the evolution of initial price regulation, it is concluded, in accordance with the discussion of "value, cost, and need" (*supra*), that the traditional public utility standards which focus on producer cost-of-service cannot have any relevance to the determination of proper initial prices for gas. The ultimate value and use of such standards after producer regulation has evolved further is uncertain, and need not be decided now. The Area Rate Proceeding above referred to may take three or four years to hear. Presiding Examiner's Report of Prehearing Conference, AR61–1, isued May 26, 1961, p. 15. The second Area Rate Proceeding, AR61–2, primarily concerning initial prices for new gas in southern Louisiana, was convened for prehearing conference on June 26, 1961. Order of May 10, 1961, instituting rate proceeding. In the meantime, while ultimate principles are being worked out, we must have a *modus vivendi* under which new gas is connected.

2. *Revenue Requirements of the Industry.* In *Phillips*, 24 FPC 537, 547, the Commission indicated that "the ultimate solution to producer regulation will be in the determination of fair prices for gas, based on reasonable financial requirements of the industry." To that end, "industry-wide data" concerning

[25] *Catco*, 360 U.S. at 388, quoted with approval in *P.S.C. of New York* v. *F.P.C.*, 287 F. 2d at 150 (CADC).

costs in given areas and for producers and groups of producers, "company-wide," will be presented in Area Rate Proceeding AR61–1. Order of April 5, 1961, 25 FPC 614 at 616.

In the case at bar, there is no evidence on this proposed method for gas price determination. The ground rules for procedure and evidence thereunder have not been evolved. See proffers, protests and pleadings filed in Proceedings AR–1 and AR–2. In the case of initial prices generally, we may not wait on the evolution of the "revenue requirements" method, but must resolve pending cases *pro tem.*

3. *Value of Service.* In conventional public utility regulation, value of service has no relevance in the determination of utility rates or prices.[16] As a practical matter, however, value of service seems to have been the controlling factor in Commission decisions and to be recognized as a matter of importance by the courts in initial price determinations.[17] In candor, it must be recognized that value of gas considerations reflect aspects of the open market in an unregulated economy.

As indicated in a prior section of this opinion, value of the Elk City gas to Panhandle is given controlling weight in connection with the 20.5 cent price. As of 1961, considering the practical consequences of a contrary ruling, the current facts as to the evolution of pricing control permit no other result.

4. *Trended Base-Period Prices.* In analogy to excess profits tax legislation and in partial analogy to OPA practices, this method of price control selects with some degree of arbitrariness (a) a period of time at which prices deemed "normal" were prevailing, and (b) geographical areas in which "normal" price differentiations then existed, and to new gas offered for sale, applies the given normal price trended for changes in costs or value of the dollar. This method seems to be the basis for the approach taken to "initial prices" by Policy Statement 61–1. See *Phillips, supra*, 24 FPC at 547.

As applied to gas prices, the method has a serious inherent defect, brought out in its application to the case at bar, in that it tends to freeze given price situations which happen to exist (mainly by historical accident as to the timing of gas marketing negotiations) during the "base period" in a given area. Those prices in such period only reflected the then market value of gas, and have no relationship to (a) the public interest in new exploration and development in "likely" areas of low base prices, or (b) the proper price for new gas of different economic characteristics (magnitude, quality, pressure, accessibility). Should producers have a 2-cent initial price differential (incentive) for drilling in the six-county Panhandle area of Oklahoma, over the adjacent counties of the enroute deliveries? Should Elk City gas have a presumptive base price of 15 cents, while south Louisiana gas has a price of 20.96 cents? See First Amendment to Policy Statement 61–1, issued October 25, 1960.

Can we logically find a 15-cent area price for Elk City gas and a 17-cent price for Pioneer gas in this proceeding? The comparative facts are as follows:[18]

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[16] *E.g.*, the high value of telephone service to a physician, or bus service to a "necessity" (auto-less) rider, does not determine the fair and reasonable levels of charges for service.

[17] In *South Georgia Natural Gas Co.*, 22 FPC 211, 220, the Commission recites the facts as to value, very similar to the facts of the present case, warranting prices centering at 21.5 cents per Mcf plus over 2 cents tax reimbursement (22 FPC at 227). In *United Gas Imp. Co.* v. *F.P.C.*, 283 F. 2d 817, 823 (CA9), the Court enumerates "value of service" considerations held to have a bearing on initial prices.

[18] Table from Panhandle's Reply Brief, page 4.

	Shell	Pioneer
Staff price	15¢	17¢.
Recoverable reserves	746,316,000 Mcf	11,529,000 Mcf.
Availability:		
Peak day	156,250 Mcf	1,580 to 7,350 Mcf.
Average day	127,701 Mcf	1,580 Mcf.
Potential average	225,000 Mcf	1,580 Mcf.
Proven acreage	39,990	960.
Number of wells	295	4.
Producing horizons	9	1.
Depth of wells	8,950 to 10,900 feet	7,977 feet.
Gathering	Yes	No.
Compression	Yes	No.
Dehydration	Yes	No.

But Policy Statement 61–1 is, as we have seen, only an *approach* to initial prices, not a determination thereof. Not only is the "area" of given prices subject to change, but "the prices will be adjusted from time to time as such facts as may come before us compel such adjustments." The base period is defined; in the case at bar we deal with 1961 conditions, not conditions as of the time of *Catco* or before.

4–a. *Base-Period Prices—Further Analysis in Principle.* Because the base-period method is the Commission's method for price control, selected after years of deliberation, and because it is relavant hereto and has not been clearly explained, the following observations are necessary with regard to its application:

(a) A tissue of engrafted exceptions, variances, and divergences, resulting in new ceilings according to the facts of each case on initial price, would defeat the purpose of simplicity, ease of administration and firm control so obviously desired. As *comparability* of gas packages comes into issue, scope is given for possible claims for an infinite variety of areas and ceilings following claims as to *value* of one supply as compared to and contrasted with selected other supply.

(b) Each exception, divergence or variance found on a given record, challenges the ingenuity of counsel for other applicants to find new reasons for nonstandard treatment of their particular new gas connections. The result in each case would, absent firm administration, depend upon ability of counsel or expert witnesses. However, the matter can be controlled. Price ceilings should be revised only on "compelling" evidence (Policy Statement 61–1, 24 FPC 818 at 820), or on "conclusive proof from the applicant that the public convenience and necessity require certification at that [new high] price." *Texas Gas Transmission Corp.*, 22 FPC 378, 388, reversed and remanded on another point, *P.S.C. of New York* v. *F.P.C.*, 287 F. 2d 146 (CADC), referred to with approval, *United Gas Improvement Co.* v. *F.P.C.*, 283 F. 2d 817, (CA9).

(c) Adjustments to area base prices for given situations are necessarily grounded on considerations of comparative *value* of new gas purchases, despite the theoretical unsoundness of this approach.

(d) Each upward revision of prices based on special circumstances will tend to set a new base for price negotiation for nearby gas, no matter how carefully the revision is circumscribed in the words of the decision. However, this effect can be mitigated or entirely controlled, in the case of interstate sales, by firm Commission action on the peripheral contracts.

(e) The Commission is working towards, but has by no means firmly established, the appropriate *areas* in which given prices are to be applicable, and the *price levels* (base period prices) to be applied in the given areas. Policy Statement 61–1 did not, and could not, make definitive determinations. The matter is still in flux; the resolution applicable to the instant case will be made *infra* herein.

5. *Policy of Deferral.* *Catco* suggests that the Commission temporize with the problem of setting proper initial price levels for new gas by approving the negotiated price after one-day suspension, subject to the condition that refund be made of any portion thereof found in subsequent rate proceedings to be excessive.[19] The use of this device for deferral of decision is particularly attractive in the case of important, valuable, unconnected reserves needed immediately by pipelines. However, on balance, the Commission has reasonably determined that the device is unacceptable because it (a) would actually establish, in negotiations, the new higher price level in the area, and (b) would compound the existing rate-case uncertainties of gas pricing. *Gulf Oil Corp.*, 23 FPC 664 at 666–667.

The Commission might also temporize by dismissing certificate applications without prejudice on the basis that given evidence such as that adduced in the case at bar is insufficient to justify negotiated prices in the absence of indications as to producer costs and revenue requirements. The Commission would thus follow the general line laid down by the courts, which have regularly remained initial price cases for more evidence. See cases cited *infra*. Such a ruling would also seem to be consistent with some of the observations made by the Commission in *Phillips*, *supra*, and Policy Statement 61–1. However, there is no indication that, at the present stage in the evolution of producer regulation, this approach will be fruitful. See Brown. J., dissenting in *United Gas Improvement Co.* v. *F.P.C.*, *supra*, Slip Opinion pp. 18 *et seq.* Control of initial prices is up to the Commission; the industry cannot be expected to produce price-reducing evidence. Until the Commission evolves new standards for price control (by way of general, industry-wide orders) the resolution of specific cases must be on the basis of evidence such as that contained in the record before us.

II. *Practical Consequences of Price Limitation.* Let us assume that, since there is no rational basis for any other price level, the Elk City certificate is offered to Shell at the highest prevailing level of nearby sales, i.e., 17 cents per Mcf. Although Shell did not directly say so on the record (perhaps as a matter of diplomacy, cf. *Catco*, 360 U.S. at 388), it is clear enough from the testimony and from current industry practice, that the certificate will be refused.[20] Shell's alternatives include: intrastate sale (Oklahoma Natural Gas Company); sale for use at the site in chemical production; "in place" sale for interstate transportation to large gas users;[21] and the "shut-in" of the gas in the hope that federal price control will be eased or abandoned.[22] Cf. Judge Brown, dissenting in *United Gas Improvement Co.* v. *F.P.C.*, *supra*, Slip Opinion pp. 20–21.

Unless the price-conditioning order in this case expressly or by implication ruled otherwise, Shell would also have the alternative to decline the certificate and resell the gas to another of the interstate pipeline bidders, e.g. to Michigan Wisconsin Pipe Line Company at a "flat thirty cents per thousand cubic feet for

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[19] This was the action taken by the Commission, at one stage, in *Catco* itself, and is the reading of slightly more general language, 360 U.S. at 389 and 392 (contracting Section 4(e) refund procedures and Section 5 action on initial rates), adopted by the Examiner in *Gulf Oil Corp.*, 23 FPC 664 at 670 *et seq.*, and generally confirmed by two Courts of Appeal, *United Gas Improvement Co.* v. *F.P.C.*, 283 F. 2d 817, 823 (CA9); *P.S.C. of New York* v. *F.P.C.*, 287 F. 2d 146, 149 (CADC).

[20] Price-conditioned certificates for less valuable unconnected gas are being currently refused. See e.g. *Phillips Petroleum Co.*, 22 FPC 694, certificates refused January 14, 1960; *Gulf Oil Corp.*, 23 FPC 664, certificates refused, case dismissed, 23 FPC 926; *Socony-Mobil Oil Co.* (Docket No. G–17849 *et al.*), temporary certificate refused May 18, 1960, withdrawal allowed by order of June 30, 1960.

[21] This alternative involves the legal issue, whether a high per Mcf price for the gas would be a relevant consideration in the transportation permit proceeding. See cases in footnote 3, *supra*.

[22] There is reason to believe that shut-in of dry gas is becoming commonplace and increasing.

this gas for twenty years." (Tr. 46.) Absent a ruling herein to the contrary (express or implied), such a proposition would have to be reheard and redecided on a new record as to the public convenience and necessity at an indefinite future time and general price level. Since it is perfectly clear that Panhandle needs the gas and needs it right now, the national public interest would require that this alternative be eliminated, and that the Commission now fix the price at which Shell can sell the Elk City gas to an interstate pipeline now or in the future. Shell would have to be told, in effect, in any price-conditioning order, that certification of the Elk City gas for interstate sale elsewhere would not be granted by the Commission, if Shell refused the price-conditioned certificate for the sale to Panhandle.

What would be the implication of such an order? Clearly, it would involve the principle of rationing and allocation procedures to be imposed by the Commission, designed to insure that new gas, in short supply and at a Commission-fixed price less than price reached by solid negotiations in a free market, is channeled to the pipeline and ultimately to the consumer area which most needs the gas.

Specifically in this case, then, a price condition would mean both (a) loss of the Elk City gas to the conventional interstate market, and (b) by implication, at least, sanctions in the nature of rationing and allocation, on later reoffer of the gas for sale to another pipeline at a higher price, to be written into the order. We are not yet ready for this step in producer regulation. We are still in an era when *value* of gas (a non-utility concept) to Panhandle and the ultimate consumers is given importance in the decision of proper initial prices. See prior sections, *supra*. Until the Commission evolves more rigid controls, industry-wide, we must take account of these consequences, and be prepared, in a price-conditioning order, to find them compatible with the present and future interests of Panhandle and its utlimate consumers.

It is implicit in the foregoing that we cannot now impose effective *ad hoc* initial price control on the Elk City gas at an amount, say 17 cents per Mcf, less than its solid market value to Panhandle of 21 cents plus fringe benefits. This does not mean that such price control will not be practical at some time in the future, when implemented properly by general orders. In candor, we should be explicit about the evolving conditions which will ultimately make pricing below levels of value practical for unusually desirable reserves such as Elk City:

1. Saturation of the given intrastate consumer market (and chemical market) for gas at higher prices than the controlled price. At present, the Oklahoma intrastate market sets the price ceilings. See *Phillips Petroleum Co.*, 22 FPC 528.

2. Elimination of the "shut-in and wait" alternative as a sound business policy for producers. This implies forced acceptance by the oil industry of gas pricing at levels less than prevailing values. The acceptance will probably not come until resistance to general orders (setting initial price levels) is broken after a waiting period during which much gas will be shut-in.

3. Rationing and allocation procedures, designed to insure that new gas priced below its value is assigned to the pipeline and consumer territory that most needs the gas, rather than by the caprice or favoritism of producers.

4. A rational basis for price fixing, other than value. Such a basis will, according to *Phillips*, be found in Shell's, or the oil industry's, "revenue requirements" in northwest Oklahoma, or nation-wide.

5. Elimination, by saturation or otherwise, of the apparent alternative open to Shell to make an "in place" sale at prices higher than the controlled price.

III. *Court and Commission Authorities.* An extended analysis of the authorities is unnecessary; those affected by or reviewing this decision are well aware

of what has been decided and said, beginning with *Catco*. The judicial authorities have expressed commendable attitudes protective towards consumers, and have decided that the concrete problems should be remanded to the Commission.[23] Generalities and attitudes are not helpful to the decision of particular cases during a period of fluid, evolving Commission policy.

The recent Commission authorities show a disposition to reduce negotiated prices by price conditions, but fail to produce a consistent pattern or policy; indeed, abound with inconsistencies. A vital matter—not, however, of logical significance—seems to be whether or not the gas is already connected, i.e., not subject to disconnection without Commission approval. Recent Commission decisions include: *Trunkline Gas Co.*, 21 FPC 704; *South Georgia Nat. Gas Co.*, 22 FPC 211; *Phillips Petroleum Co.*, 22 FPC 528; *Phillips Petroleum Co.*, 22 FPC 694, 1021; *Western Nat. Gas Co.*, 23 FPC 332; *El Paso Natural Gas Co.*, 23 FPC 369, 610, affirmed *sub nom Texaco, Inc.* v. *F.P.C., supra; Gulf Oil Corp.*, 23 FPC 664, 926, *Peoples Gulf Coast Nat. Gas Pipeline Co.*, 24 FPC 1, 106, 323, 351, *Hope Nat. Gas Co.*, Dkt. No. CP60–75 *et al.*, order issued July 11, 1960; *Humble Oil & Refining Co.*, 24 FPC 191; *Natural Gas Pipeline Co. of America*, 24 FPC 222, 305, amendment denied, October 10, 1960, 24 FPC 853; *Trunkline Gas Co.*, 24 FPC 1020, Opinion No. 339, issued November 29, 1960; *Texaco, Inc.*, 24 FPC 979, Dkt. No. G–18078 *et al.*, issued November 22, 1960, rehearing granted January 19, 1961. Nothing is found in these decisions specifically applicable to the resolution of the price issue in the case at bar.

Findings and Conclusions

(1) *Approach.* The decision of this or any other specific case must be in accord with the general direction of evolving Commission policy. At the present writing, the policy is one of gradualism in the application of price restrictions to new unconnected gas supplies. The *value* of gas to willing pipeline buyers and ultimately to willing consumers—the *need* for new gas on the part of the same interests—are considerations of high importance. An important breach of existing price ceilings (such as is here involved) is a serious step, not to be undertaken without the most careful balancing of all interests, including the public interest in the ultimate attainment of regulated prices at levels below, and perhaps far below, those of the free market.

While the Commission evolves further general policy towards price restrictions and standard contracting practices, connection of new gas supplies must go on. In the average case of small reserves or casinghead gas, the Commission can probably at present hold the price line with confidence that such supply will be connected at prevailing area prices. Such is not the present case. We here, at the outset of effective regulation, face the unusual situation in terms of value and need, for which an exception must be made.

(2) *Elk City Reserves: Area Price.* The 20.5-cent per Mcf initial price for the Elk City reserves is fully consonant with the public interest, and should be certificated as negotiated and applied for. It is suggested that, as in the Knox Field case,[24] the initial price be incorporated into the general area pricing

[23] *P.S.C. of New York* v. *F.P.C.*, 361 U.S. 195; *United Gas Improvement Co.* v. *F.P.C.*, 283 F. 2d 817 (CA9), *certiorari* denied April 17, 1961; *Public Service Commission* v. *F.P.C.*, 287 F. 2d 146 (CADC), *certiorari* denied April 17, 1961; *same* v. *same*, 287 F. 2d 143 (CADC); *United Gas Improvement Co.* v. *F.P.C.*, 287 F. 2d 159 (CA10); *United Gas Improvement Co.* v. *F.P.C.*, Nos. 18112, 18113 (CA5), decided February 22, 1961, 290 F. 2d 133 and 147; *Texaco Inc.* v. *F.P.C.*, Nos. 18349, et al. (CA5), decided April 14, 1961, 290 F. 2d 149. In the *Texaco* case, the Fifth Circuit affirmed a price condition of *already connected* 20-cent gas to a 17.7-cent level.

[24] *Phillips Petroleum Co.*, 22 FPC 694.

patterns established by Policy Statement 61-1.[25] As restricted to the specific dedicated reserves, the Elk City price will not establish or tend to establish a new level for other gas in the Anandarko Basin, because such other gas does not have the unusual cost-saving features of such reserves discussed *supra*.

It is also specifically concluded that as of the current stage in producer regulation, it is not possible to establish a discount to the negotiated 20.5-cent per Mcf price for the Elk City reserves except on an arbitrary or impressionistic basis, and that such a discount would fail to allow for clear qualitative and quantitative differences between Elk City and other gas, and would be inequitable and discriminatory.

(3) *Enroute Contracts—Area Price.* The 17-cent per Mcf initial price for the enroute reserves is fully consonant with the public interest, and should be certificated as negotiated and applied for. The geological and marketing area from which the enroute sales will be made is a part of the same area as that of the six Panhandle counties. As a result of the specific determinations on the record herein, 17 cents per Mcf should be established as the area price for new gas sold from the Oklahoma counties of Woods, Alfalfa, Woodward, Major, and Dewey, and for gas (except Elk City gas) sold from Beckham and Washita Counties.

(4) *Btu Adjustment: Shell and Enroute Contracts.* On the record herein, the conditioning of certification on elimination of upward price adjustment for Btu content of over 1,000 per Mcf is unnecessary to the protection of consumer interest, and would unfairly discriminate against the producers in respect of a conventional contract provision (with a basis in extra value of high Btu gas) often accepted by the Commission in prior certifications.[26]

In recent months, several temporary certificates issued by the Commission have been conditioned on the elemination of upward Btu adjustment. See e.g. Commission public files in Docket Nos. G-19542, CI60-699, CI60-602, CI60-578, CI61-314, CI61-155 and CI61-16. The question, whether the Commission can legally make such a requirment is before the courts in several cases, see e.g. *Pure Oil Co.* v. *F.P.C.*, CA 7 No. 13243 argued May 25, 1961, and *J. M. Huber Corp.* v. *F.P.C.*, CA3 No. 13535 argued June 23, 1961, both pending undecided.

There is no need to go into the legal issue in this case. Staff has presented no evidence showing that the Btu adjustment provision works any special detriment to Panhandle and its customers in this case[27]; Staff relies on the general premise that this conventional provision should be eliminated from *all* purchase contracts. Assuming the correctness of the premise, it is not appropriate to effect the desired result piecemeal, by application of the elimination policy retroactively to such contracts as may be scrutinized in particular proceedings. The appropriate way to effect the result is, to enter a Commission order of general application to all future contracts, after due rule-making proceedings under the Administrative Procedure Act. Only this method avoids the problem of discrimination.

The Commission has, consistently with this conclusion, recently proposed to rule generally against, *inter alia*, future upward price adjustment contract provisions for gas with Btu content of over 975 per cubic foot. *Notice of Proposed Additions to the Commission's Statements of General Policy* (etc.), Docket

[25] Note that in *Knox Field* and the instant case, the price pattern thus incorporated will be based on full hearings and specific determination, thus will be firm rather than tentative and statistical.

[26] See, e.g., *Phillips Petroleum Co.*, 22 FPC 528, and *Natural Gas Pipeline Co. of America*, 24 FPC 222.

[27] Of course, there is a price differential which results, as pointed out in the statement of facts. The same differential exists in other certificated contracts containing the Btu provision.

No. R–200, issued May 22, 1961. The results of the proposal may or may not be a rule; in all events, the rule will not affect prior contracts such as those involved in the proceedings at bar.

(5) *Rate-of-Take: Shell and Enroute Contracts.* On the exceptional facts of this case, the rate-of-take provisions of the Elk City contract are consonant with the public interest, and the Commission should not offer Shell a certificate conditioned on the stretch out of Panhandle's takes. The facts, *supra*, are very clear that Panhandle needs gas for existing customers and replacement of overproduction, and Panhandle needs the gas *now*. Panhandle and its customers are advantaged, not detrimented, by fast Elk City take-down. Panhandle's future buying program for conventional gas supply will be expected, as a matter of good business, to provide for the distant as well as the immediate future.

In reaching this conclusion, weight is necessarily given, under current conditions, to the negotiating facts of life showing that Shell's deal with Panhandle (at a price less than other offers) was principally motivated by rate-of-take as written into the contract.

As in the matter of Btu adjustment, Staff's approach is towards a general problem of the industry—preservation of long life index of reserves, to care for future needs—which should not be resolved by an attempt on the part of the Commission to retroactively renegotiate the Elk City contract. The problem has been properly attacked by the proposal of a general order for future application to contracts entered into after the order becomes effective. *Non-Acceptability of Contracts Between Independent Producers and Interstate Natural Gas Companies* (etc.), Docket No. R–199, issued May 22, 1961.

With regard to the enroute contracts, most of the conclusions stated above are of equal applicability. In addition, the standard enroute contract rate-of-take provision results in a conventional 20-year life index, worked out to avoid (1) the inaccuracies and uncertainties of depletion based on advance estimated, (2) the necessity for continuous reserve recalculation, (3) wide fluctuation in estimated deliverability.

(6) *Take-or-Pay-for: Shell and Enroute Contracts.* Because of Panhandle's enormous and growing need for gas, it has never since commencing operations paid for gas not taken, and there is no likelihood that such a condition will occur in the future, under the facts of record in this proceeding. The take-or-pay-for provisions as written, with long make-up periods advantaging Panhandle, are fully consonant with the public interest. Again, this matter of general concern, not of particular detriment to Panhandle or the consumers in this proceeding, is properly dealt with by the proposed rule for the future announced in Docket No. R–199, *supra*.

(7) *Line Blockage From High Btu Gas.* There is no evidence supporting Staff's contention that the gas here involved will cause line blockage or other damage to Panhandle's pipeline facilities. Nor is there any evidence that Panhandle will have to install liquid extraction facilities in order to handle the gas in its lines. Staff's contention is speculative, and disproved by Panhandle's affirmative evidence.

(8) *Storage Aspects.* Panhandle and Shell claim extra value for the contract provision under which, after production from Elk City ceases, Panhandle may acquire the gathering and other facilities there in place and may use the field for storage of injected gas from other fields. It is not possible, however, to assign any concrete dollar value to the storage feature. Conditions which may obtain 15 years from now with respect to the desirability of storage at Elk City (towards the far end of Panhandle's line) are not predictable. Panhandle is not buying a storage field, and current ultimate consumers should

not, in terms of purchased gas costs, be assessed with any amounts on that account.

(9) *Matters Not Controverted.* To satisfy judicial and other authority, formal findings are made on the following points:

(a) The contracts were made at arm's length, and represent the minimum terms of the producers for sale of the gas, and Panhandle's view of the best deal it could make for gas.

(b) The price escalates 2.5 cents per Mcf every five years, and the buyer pays one-half of all taxes. There are no "favored nations" or other indefinite escalation clauses. Operation of the fixed escalation clause is, of course, subject to Commission suspension and review under Section 4(e) of the Natural Gas Act.

(c) The 20.5 cent price to Shell and the 17-cent price to the other producers will not trigger increases in other Panhandle contracts.

(d) The certification of the sales involved here will not cause Panhandle to seek a rate increase.

(e) All producers who have not withdrawn are willing and able to perform under their Panhandle contracts, and to conform to the Natural Gas Act and the regulations thereunder. The enroute producers who have cancelled their contracts and withdrawn from this proceeding should be permitted to rescind their cancellations and reinstate their applications, *nunc pro tunc*, within 30 days from the date of the issuance of this order, under the exact terms and conditions as originally contracted and presented. In the event of any such reinstatement, certificates should issue to such producers on the record herein.

(f) Panhandle is able and willing to undertake the construction of the Elk City lateral, and to conform to the Natural Gas Act and the regulations thereunder.

ORDER

WHEREFORE, IT IS ORDERED, SUBJECT TO REVIEW BY THE COMMISSION, THAT:

(A) A certificate of public convenience and necessity is hereby issued to: Panhandle Eastern Pipe Line Company, Shell Oil Company, Calvert Petroleum Company, and King-Stevenson Oil Comapny, Inc. for the construction and operation of facilities for the transportation of natural gas in interstate commerce for resale, and for the sale of natural gas by independent producers, all subject to the jurisdiction of the Commission, as prayed for in the respective applications filed by such parties in these proceedings.

(B) Within 30 days from the date of this order Pioneer Production Corporation, Ashland Oil & Refining Company and Union Oil Company of California shall have the option to rescind their cancellation of their contracts with Panhandle and their notices of withdrawal from this proceeding and to notify the Commission of their resubmittal of their applications on the same terms and conditions as originally applied for and proven in these proceedings. In the event such resubmission is made a certificate will thereupon issue, *nunc pro tunc*, for the sale of natural gas in interstate commerce by said producers as prayed for in their respective original applications herein.

(C) The certificates issued herein shall be accepted in writing and under oath within 30 days from the date of the final determination of these proceedings in accordance with Section 1.30 of the Rules of Practice and Procedure.

(D) The general terms and conditions of Paragraphs (a), (b), (c) and (e) of Section 157.20 of the regulations under the Natural Gas Act shall attach to the issuance of the certificate granted to Panhandle Eastern Pipe Line Company in Paragraph (A) above, and the time within which the facilities hereby author-

ized shall be constructed and placed into actual operation is hereby fixed at six months from the date of the issuance of this order.

(E) The certificates issued to the independent producer applicants are not transferable and shall be effective only so long as the respective applicants continue the acts and operations hereby authorized in accordance with the provisions of the Natural Gas Act and the rules, regulations and orders of the Commission.

(F) The grant of the certificates herein shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act, or of Part 154 of the Regulations thereunder. Such grant is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicants. Further, the action in this proceeding shall not foreclose nor prejudice any further proceedings or objection relating to the operation of any price or related provision in the gas purchase contracts herein involved.

ROBERT M. WESTON,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

PORTLAND GENERAL ELECTRIC COMPANY, PROJECT NO. 2030

ORDER FURTHER AMENDING LICENSE (MAJOR)

(Issued January 16, 1962)

Application was filed June 20, 1961, by Portland General Electric Company, licensee for major Project No. 2030, located on the Deschutes River in Jefferson County, Oregon, and affecting lands of the United States within the Deschutes National Forest, lands of the Warm Spring Indians and other lands of the United States, for further amendment of the license for the project, seeking modification of Articles 10 and 31 as hereinafter specified. Project No. 2030 consists of two developments known as Round Butte and Pelton developments.

The requested revision of Article 10 would modify the clearing requirements for the Round Butte reservoir to require complete clearing of margins and bottoms only between elevations 1,850 feet and 1,950 feet (5 feet above high-water level) together with clearing of merchantable timber below elevation 1,850 feet, rather than the presently required complete clearing of the entire reservoir up to high-water level.

According to the application, the changes in Article 10 are necessary and desirable because savings of about $250,000 can be affected by leaving willows, alders and other small trees below elevation 1,850 feet, all of which will be well submerged during the recreational season. Based upon costs experienced by Applicant in clearing the Pelton reservoir, our staff advises that the actual savings to be realized by partial clearing below elevation 1,850 feet should exceed Applicant's estimated savings by a substantial amount. Moreover, this proposed alternative method of clearing the reservoir has been authorized by the Commission in several other licenses and, besides reducing the cost of clearing, has proved acceptable for project purposes, including recreation.

Applicant seeks revision of Article 31 to extend by one year—to September 1, 1962—the time for submission of revised Exhibits F and K for the Round Butte development other than for the 230-kv transmission line. The surveys and land

acquisitions required in connection with the revised exhibits could not be completed prior to September 1, 1961, the date presently specified for submission, and a year's extension is needed to complete the preparation of these exhibits.

Although in his report on the application for license the Secretary of Agriculture recommended insertion in the license of Article 10 which requires full clearance of the Round Butte reservoir, that agency in its later report on the pending application for amendment advises that the proposed amendment of Article 10 will not be inconsistent with the purposes for which the Deschutes National Forest and the Crooked River National Grasslands were created or acquired, provided that clearing in potential recreation areas on National Forest land be limited to normal high water of Round Butte reservoir and to such trees in the recreation areas along the margins of that reservoir which may die during operation of the project; and that the Forest Service will designate the potential recreation areas to the authorized representative of the Commission.

An Assistant Secretary of the Interior, in reporting on the application, has requested that an additional provision be included in any amended license that disposal of material cleared from Round Butte reservoir be in a manner which will result in no harmful effects on fish resources and that ashes from such disposal be kept out of the rivers.

By letter filed September 26, 1961, Applicant furnished us copies of letters to Applicant dated August 14, 1961, and August 18, 1961, respectively, from the Oregon State Game Commission and the Fish Commission of Oregon indicating no objection to the proposed revision of Article 10. No objection to such revision was raised in the Oregon State Game Commission's letter to us dated August 31, 1961.

The Commission finds:

(1) Public notice of the filing of the application for amendment has been given. No protests have been received.

(2) The license for Project No. 2030, further amended as hereinafter ordered, will not interfere or be inconsistent with the purposes for which the Deschutes National Forest was created or acquired or with the purposes of any reservation or withdrawal of public lands, and is in the public interest.

The Commission orders:

(A) The license for Project No. 2030 is further amended, effective as of September 1, 1961, as follows:

PARAGRAPH I. Article 10 of the license, as amended, is further amended to read as follows:

Article 10. The Licensee shall, prior to flooding, clear the area of the three project reservoirs as follows:

Pelton Reservoir—All bottoms and margins of the reservoir area between the plane 5 feet above normal high-water level and the plane at 1,555 feet, and all coniferous trees from the bottoms and margins below the plane at elevation 1,555 feet;

Regulating Reservoir—All lands in the bottoms and margins of the reservoir up to high-water level; and

Round Butte Reservoir—All lands in the bottoms and margins of the reservoir area between the plane at elevation 1,950 feet (5 feet above the normal high-water level) and the plane at elevation 1,850 feet, and all merchantable timber and debris created by the logging thereof from the bottoms and the margins below the plane at elevation 1,850 feet; *Provided, however,* That in areas designated as potential recreation areas by the Commission's representative, upon advice of the Forest Service, clearing shall be limited to normal

high-water level of the reservoir, and to such trees in the recreation area as may die during operation of the project;

and shall clear and keep clear to an adequate width lands of the United States along open conduits, and shall dispose of all temporary structures, unused timber, brush, refuse, or inflammable material resulting from the clearing of the lands or from the construction and maintenance of the project works. In addition, all trees along the margins of reservoirs which may die during operations of the project shall be removed. The Licensee shall dispose of the material resulting from clearing of the lands within Round Butte reservoir so that there will be no harmful effects on fish resources. All ashes resulting from this disposal shall be kept out of the rivers. The clearing of the lands and the dipsosal of the material shall be done with due diligence and to the satisfaction of the authorized representative of the Commission.

PARAGRAPH II. Article 31 of the license, as amended, is further amended to read as follows:

Article 31. The Licensee shall submit for Commission approval by September 1, 1962, revised Exhibits F and K for the Round Butte development other than the 230-kv transmission line, in accordance with the Commission's rules and regulations.

(B) This amendment in the manner set out above shall not operate to alter or amend the license in any other respect, and shall not in any way constitute a waiver of any other part, provision of conditon of the license as heretofore amended.

(C) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313(a) of the Federal Power Act and failure to file such an application shall constitute acceptance of this amendment of license. In acknowledgment of the acceptance of this amendment of license, it shall be signed for the Licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles Ross.

HOUSTON TEXAS GAS AND OIL CORPORATION, DOCKET NOS. G–9262, CP62–52

ORDER FURTHER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND CANCELLING DOCKET NUMBER

(Issued January 17, 1962)

On August 24, 1961, Houston Texas Gas and Oil Corporation (Applicant) filed in Docket No. CP62–52 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the increase in quantities of natural gas to be delivered to nine of its existing resale and direct sale customers above the volumes authorized to be delivered to said customers in Docket Nos. G–9262, *et al.*, all as more fully set forth in the application. This application is being treated as a petition to further amend the existing certificate authorization in Docket No. G–9262.

The proposed increases in deliveries will be under Applicant's preferred interruptible rate schedules and involve an additional 9,509,856 Mcf per year or an average of 26,000 Mcf per day.[1] No additional facilities are proposed.

[1] Based on gas having a heating value of 1,000 Btu per cubic foot.

The proposed increased sales and deliveries are as follows:

Customer	Annual preferred interruptible service (Mcf)		
	Column (1) G–9262 authorized volumes	Column (2) CP62–52 proposed increase	Column (1) plus column (2)
Resale:			
Peoples Gas System, West Coast Division [1]	113,000	1,438,000	1,551,000
Gulf Natural Gas Company:			
Ocala Division [2]	53,436	137,946	191,382
Panama City Division [3]	346,093	801,162	1,147,255
The Houston Corporation:			
Orlando Division [4]	[5] None	73,250	73,250
Miami Division [6]	[5] None	49,640	49,640
Florida Public Utilities Company	330,000	216,900	546,900
Florida Home Gas Company	[5] None	14,600	14,600
Direct sale (power plants):			
City of Blountstown	3,324	58,676	62,000
City of Tallahassee	115,045	3,534,955	3,650,000
City of Lakeland	140,610	3,071,390	3,212,000
City of Starke	5,113	113,337	118,450
Total	1,106,621	9,509,856	10,616,477

[1] Formerly Tampa Gas Company.
[2] Formerly Ocala Gas Company.
[3] Formerly West Florida Gas and Fuel Company.
[4] Formerly South Atlantic Gas Company.
[5] These customers purchase gas from Houston under other service categories, i.e., firm, primary interruptible.
[6] Formerly Florida Power & Light Company.

In the case of Peoples Gas System, Inc., West Coast Division, Gulf Natural Gas Company, both divisions, and Florida Public Utilities Company, industrial and commercial gas requirements have grown far beyond those existing at the time of the hearings in Docket Nos. G–9262, *et al.*, similarly, in the cases of the Orlando and Miami divisions of The Houston Corporation and in the case of Florida Home Gas Company, requirements have developed that were not previously anticipated. Requirements of the four municipalities for gas for electric generation have increased as a result of the growth in population and industrial activity in their respective service areas.

Applicant proposes to make the additional deliveries possible as a result of (1) cancelling 194,063 Mcf per year of the preferred interruptible sales to the cities of Avon Park, Graceville, and Green Cove Springs, for which authorizations were revoked by the Commission's letter order dated May 11, 1961, and (2) upgrading of the remaining balance by reducing existing primary interruptible sales and correspondingly increasing the preferred interruptible service.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act and the public convenience and necessity require that the order of the Commission accompanying Opinion No. 301 in Docket Nos. G–9262, *et al.*, issued December 28, 1956, as amended, be further amended as hereinafter ordered.

The Commission orders:

(A) The order of the Commission accompanying Opinion No. 301 in Docket Nos. G–9262, *et al.*, issued December 28, 1956, as amended, be and the same is hereby further amended to authorize an increase in quantities of natural gas to be delivered to nine of the existing resale and direct sale customers of Houston Texas Gas and Oil Corporation, as hereinbefore described and as more fully described in the application in Docket No. CP62–52.

(B) In all other respects said order, as amended, referred to in paragraph (A) above shall remain unchanged and in full force and effect.

(C) Docket No. CP62-52 is hereby cancelled.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

HOUSTON TEXAS GAS AND OIL CORPORATION, DOCKET NOS. G-9262, RP61-3, AND RP62-4; COASTAL TRANSMISSION CORPORATION, DOCKET NOS. G-9960 AND RP61-4

ORDER GRANTING APPLICATION FOR ISSUANCE OF SUBPOENA DUCES TECUM

(Issued January 17, 1962)

These proceedings involve requests to modify certificate conditions and proposed increased rates under Sections 4, 7, and 15 of the Natural Gas Act. Direct cases have been submitted by the Respondents, Sun Oil Company (Sun), an intervener herein, and the Commission staff. These proceedings are presently in recess until January 29, 1962, at which time the Commission staff is to file its direct case on original cost studies made on the original construction costs of the subject project and a revised direct case reflecting these original cost studies.

On January 5, 1962, Sun filed an application for a subpoena *duces tecum*, wherein it requested that a subpoena be issued to the President of the Respondent companies requiring him to produce certain memoranda, letters, schedules, reports and financial and other statements and to testify thereon on January 22, 1962. The documents requested to be produced are described in said application under paragraphs (A), (B), (C), (D), and (E).

In support of its application, Sun states that the documents identified in Items 1 through 6 under paragraph (A) of its application contain forecasts of operating results for the year 1960 through 1964 on the basis of operating the originally certificated facilities; that these estimates are necessary to assess the reasonableness of the proposed rates herein; and that the operating results of the parent company, Houston Corporation, are pertinent to these proceedings in that they relate directly to the amount of income taxes includable in the Respondents' costs of service. In support of its request for the report identified in paragraph (B) of its application, Sun states that the operating results anticipated under the newly certificated expansion program of the Respondents, which are contained in this report, are necessary to test the reasonableness of Respondents' rates and would update the information on this aspect of the case, which information is contained in Exhibit Nos. 44, 50, and 51 admitted to evidence in these proceedings. In support of its request for the financial statements identified in paragraphs (C) and (D) of its application, Sun states that similar financial statements were admitted into evidence, Exhibit Nos. 26, 27, 48, and 49, and that the subject financial statements are necessary to update this information especially in light of the recent development of the accrual of Federal income taxes on the books of Coastal Transmission Corporation. In support of its request for the statement identified in paragraph (E) of its application, Sun states that the estimates contained in the subject statement should be reviewed in testing the reasonableness of the proposed rates. Sun, further, states that the "requested information containing, among other matters, projections of sales and revenues

beyond the first three years of operations, goes directly to the subject of anticipated revenues", which bears on the issue of whether the additional and improved loads beyond the development period would be the solution to the problem of improving the Respondents' rate of return. In addition, Sun states that production of these documents would not place a burden on Respondents.

The Respondents filed a joint answer to Sun's application for a subpoena *duces tecum*, wherein they agree to furnish copies of the documents described in paragraphs (C) and (D) of Sun's application. However, with respect to the documents described in paragraphs (A), (B), and (E) of Sun's application, the Respondents, while conceding that these documents contain future sales forecasts, contend that they are not relevant or material to the issues involved in these proceedings inasmuch as the forecasts go beyond the test period of these proceedings. However, in its application, Sun states that the Commission, in setting prospective rates, must look at the operating results anticipated under the expanded operations. In view of the statements of both the Respondents and Sun, it would appear that one of the issues involved in these proceedings is the proper test period for determining the reasonableness of Respondents' rates and, inasmuch as financing of the expanded facilities were not completed until December 22, 1961, it appears that the forecasts contained in the requested documents will not extend beyond the third year of operations of the expanded facilities.

Section 6(c) of the Administrative Procedure Act, 5 U.S.C. § 1005(c), reads, in part, as follows:

> * * * Agency subpoenas authorized by law shall be issued to any party upon request and, as may be required by rules of procedure, upon a statement or showing of general relevance and reasonable scope of the evidence sought. * * *

The Commission is empowered to issue subpoenas (Section 14(c) of the Natural Gas Act) and has promulgated rules of procedure for issuance thereof (Section 1.23(a) of the Rules of Practice and Procedure).

The documents requested by Sun in its application for a subpoena appear to be generally relevant and material to the issues involved in these proceedings and meet the requirements of our regulation for issuance of a subpoena *duces tecum*.

As stated hereinbefore, these proceedings are presently in recess until January 29, 1962. Sun, in its application, states that it intends to offer revised exhibits to reflect therein the pertinent data in the documents specified in its application and the results of the staff's original cost studies. In order to avoid further delay of these proceedings, Sun requests that the subpoena be returnable on January 22, 1962, one week prior to the scheduled reconvening of these proceedings. In view of the foregoing, it is determined that the subpoena ordered herein should be made returnable on the date requested by Sun.

The Commission orders:

That an appropriate subpoena *duces tecum*, in the usual form, be issued to W. J. Bowen, President of Houston Texas Gas and Oil Corporation and Coastal Transmission Corporation, to compel him to appear and produce the documents described in paragraphs (A), (B), (C), (D), and (E) of Sun's application for issuance of a subpoena *duces tecum* filed herein on January 5, 1962 at a hearing to convene on January 22, 1962 at 10:00 a.m. (e.s.t.) in a Hearing Room of the Federal Power Commission, 441 G Street NW., Washington, D.C.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

HOUSTON TEXAS GAS AND OIL CORPORATION, DOCKET NO. CP62-74

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 18, 1962)

On September 22, 1961, as supplemented on November 2, 1961, Houston Texas Gas and Oil Corporation (Applicant) filed in Docket No. CP62-74 an application pursuant to Section 7(c) of the Natural Gas Act for a certficate of public convenience and necessity authorizing the construction and operation of certain natural gas pipeline facilities in order to sell and deliver natural gas on a firm and interruptible basis to two new direct industrial customers in the Port Tampa area, Flordia.

Applicant proposes to construct and operate approximately 6.1 miles of 4-inch lateral pipeline extending from a point of interconnection with its 8-inch lateral, serving the Bartow Plant of the Flordia Power Corporation, Pinellas County, Florida, and across Old Tampa Bay to the industrial plants on National Gypsum Company (Gypsum) and Tiffany Tile Corporation (Tiffany), together with meter and regulating facilities. Applicant states that Gypsum will use natural gas in the processes of drying and calcining of gypsum rock and in the drying of gypsum board, and that Tiffany will use natural gas for firing kilns in the process of manufacturing glazed ceramic tile. Both Gypsum and Tiffany have indicated that they prefer natural gas in their manufacturing processes because of fuel economy, improved quality of finished products and increased plant productivity.

Pursuant to contracts entered into with the two industrial customers, Applicant will deliver the following maximum daily quantities of natural gas:

	Therms
Gypsum, preferred interruptible	35,8000
Tiffany:	
Firm	820
Preferred interruptible	5,860

The estimated cost of the proposed construction of facilities is $300,000, which cost will be financed from internally generated funds.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 11, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Houston Texas Gas and Oil Corporation, a Delware corporation having its principal place of business in St. Petersburg, Florida, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of December 28, 1956, in Docket Nos. G-9262, *et al.* (16 FPC 118).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportation and delivery of natural gas in interstate commerce, subject to the jurisdiction of the Commission and the construction and operation thereof

by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities and the proposed transportation and delivery of natural gas by Applicant, are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(1), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Houston Texas Gas and Oil Corporation, to construct and operate the proposed facilities and to transport and deliver to National Gypsum Company, on a preferred interruptible basis, a maximum daily quantity of 35,800 therms of natural gas and to transport and deliver to Tiffany Tile Corporation, on a firm basis, a maximum daily quantity of 820 therms of natural gas, and, on a preferred interruptible basis, a maximum daily quantity of 5,860 therms of natural gas, as hereinbefore described, all as more fully described in the application, as supplemented, herein, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(1), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(C) The facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 6 months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

PENNSYLVANIA ELECTRIC COMPANY AND PENNSYLVANIA POWER COMPANY, DOCKET NO. E-7004

ORDER AUTHORIZING ACQUISITION AND MERGER OR CONSOLIDATION OF FACILITIES

(Issued January 18, 1962)

Pennsylvania Electric Company (Penelec) and Pennsylvania Power Company (Penn Power) filed a joint application on July 14, 1961 and amendments thereto on July 28 and October 4, 1961, pursuant to Section 203 of the Federal Power Act, for authorization to acquire the electric distribution properties of Carpenter

Light and Power Company (Carpenter). Penelec, Penn Power and Carpenter are corporations organized under the laws of the Commonwealth of Pennsylvania and doing business in that State, with their principal business offices at Johnstown, New Castle and Meadville, Pennsylvania, respectively.

Penelec provides electric service within a territory located in western, northern and south central Pennsylvania, and furnishes electric service at wholesale to five municipalities which are engaged in the distribution of electric energy and to fourteen rural electric cooperatives. As lessee of the property of The Waverly Electric Light and Power Company, a wholly-owned subsidiary, Penelec also serves the Village of Waverly, New York and vicinity. Penn Power furnishes electric service in 136 communities, as well as in rural areas of five counties of Pennsylvania, and also sells electric energy to four municipalities for resale therein. Carpenter purchases its entire energy requirements, wholesale, from Penelec, and furnishes electric service to portions of Crawford, Erie, Mercer and Warren Counties, all in Pennsylvania.

By an Agreement, dated as of March 31, 1961, Carpenter agreed to sell all of its property, excluding cash and prepaid insurance, to Penelec and Penn Power, for a consideration of $2,150,000. Applicants state that the price was determined among the three parties to the Agreement through arms' length negotiation. By a subsequent Apportionment Agreement, dated as of May 22, 1961, Penelec and Penn Power agreed to a division of Carpenter's property and of the consideration therefor. Penelec will take over the portion serving about 2,349 customers in parts of Crawford County, and the few customers in Erie, Mercer and Warren Counties, paying therefor $1,053,750, subject to adjustments. Penn Power will take over the portion situated in the southwest corner of Crawford County serving about 3,461 customers in Conneaut Lake Borough and the Townships of East Fallowfield, West Fallowfield, North Shenango, South Shenango, West Shenango, Sadsbury, and Summit Township, paying therefor $1,096,250, subject to adjustments.

Under the provisions of the Agreement, Penelec, which presently supplies all of the requirements of Carpenter, will continue to supply the requirements of Penn Power for that portion of Carpenter's property which it acquires until such date as Penn Power shall have completed the building of a transmission line or lines connecting the service area of Carpenter to be acquired, with the present service area of Penn Power and Penn Power's facilities. Upon completion of the building of the said transmission facilities the present service area of Carpenter to be acquired by Penn Power will then be served from Penn Power's own facilities.

The application indicates that Carpenter's properties are recorded at original cost as approved by the Pennsylvania Public Utility Commission. The following statement shows the amounts for the facilities which are to be acquired by the two vendee companies, the considerations therefor, and the acquisition adjustments which will be created by the transactions:

	As of Apr. 30, 1961	
	By Penelec	By Penn Power
Electric plant (original cost):		
Electric plant in service	$835,550	$1,078,351
Construction work in progress	1,866	480
Total electric plant	837,416	1,078,831
Accumulated provision for depreciation	(176,795)	(228,809)
Electric plant less depreciation	660,621	850,022
Nonutility property	940	
Plant materials and supplies	12,500	12,500
Total assets	674,061	862,522
Consideration	1,053,750	1,096,250
Electric plant acquisition adjustment	379,689	233,728

As indicated above, an Electric Plant Acquisition Adjustment of $379,689 will be created on the books of Penelec. General Public Utilities, the parent corporation of Penelec, will make a cash contribution of $379,689 to Penelec, authorization having been granted by the Securities and Exchange Commission by order issued September 7, 1961 (File No. 70-3982) in accordance with the provisions of the Public Utility Holding Company Act of 1935. On the books of Penelec this contribution will be recorded by a debit to Cash and a credit to Miscellaneous Paid-in Capital. Penelec's Acquisition Adjustment of $379,689 will be completely eliminated by a debit to Miscellaneous Paid-in Capital and a credit to Electric Plant Acquisition Adjustments.

An Electric Plant Acquisition Adjustment of $223,728 will be created on the books of Penn Power, which proposes to amortize the Acquisition Adjustment over a period of 10 years by debits of $23,373 each year to Account 406, Amortization of Electric Plant Acquisition Adjustments, and credits of the same amount each year to Electric Plant Acquisition Adjustments. However, based upon Commission precedents for the disposition of Electric Plant Acquisition Adjustments, Penn Power's Electric Plant Acquisition should be amortized, over a period of not more than 10 years, by debits to Account 425, Miscellaneous Amortization, instead of by debits to Account 406.

Applicants state that the acquisition of the respective portions of Carpenter's property by Penelec and Penn Power will provide in each case a larger operating organization which should result in better service to the customers served by the facilities to be acquired, and that the greater financial strength of the respective companies, as well as the opportunity for them and for their parent corporations to obtain financing for additions and improvements to their respective systems at lower cost, will be beneficial to the customers served by those systems.

Applicants state that, upon completion of the transfers of property, each of the Applicants proposes to make its system rates effective in the territory acquired by it from Carpenter, within the first full month of service after acquisition; and, the amounts of electric revenue to be collected in their respective newly acquired territories will be less than the amounts which would have been collected under Carpenter's rate schedules. According to the application, the proposed acquisitions of property will have no effect upon any contract for the purchase, sale or interchange of electric energy by Penelec or Penn Power other than Penelec's contract with Carpenter.

Written notice of the application has been given to the Pennsylvania Public Utility Commission and to the Governor of that State. Notice of the application was also published in the Federal Register on August 1, 1961 (26 F.R.

6868), stating that any person desiring to be heard or to make any protest with reference to said application should, on or before the 14th day of August, file with the Federal Power Commission, Washington 25, D.C., petitions or protests. No petition or protest or request to be heard in opposition to the granting of the application has been received.

The Pennsylvania Public Utility Commission, by orders dated January 2, 1962, approved the proposed acquisitions of facilities by Penelec and Penn Power in the manner and for the purposes described above.

The Commission finds:

(1) Penelec, a Pennsylvania corporation, owns and operates facilities, among others, for the transmission and sale at wholesale of electric energy which is transmitted between the States of Pennsylvania and Maryland and between the States of Pennsylvania and New York, and consumed at points outside the State in which it is generated, all of which facilities are in addition to and do not include facilities used for the generation of electric energy, facilities used in local distribution, or only for the transmission of electric energy consumed wholly by the transmitter, and Penelec is, therefore, a public utility within the meaning of that term as used in Section 201 of the Federal Power Act.

(2) Penn Power, a Pennsylvania corporation, owns and operates facilities for the transmission and sale at wholesale of electric energy which is transmitted between the States of Pennsylvania and Ohio and is consumed outside the State in which it is generated. These facilities are in addition to and do not include facilities used for the generation of electric energy or facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or facilities for the transmission of electric energy consumed wholly by the transmitter. Applicant is, therefore, a public utility within the meaning of that term as used in Section 201 of the Federal Power Act.

(3) The electric facilities which Carpenter currently owns and/or operates do not include facilities for the transmission or sale at wholesale of electric energy for resale in interstate commerce; and Carpenter is, therefore, not now a public utility within the meaning of that term as used in Section 201 of the Federal Power Act.

(4) By the proposed transactions, as described above, Penelec will acquire and merge or consolidate with its facilities, subject to the jurisdiction of the Commission, a portion of the electric facilities of Carpenter, another person, within the meaning and subject to the requirements of Section 203 of the Federal Power Act; and Penn Power will acquire and merge or consolidate with its facilities, subject to the jurisdiction of the Commission, a portion of the electric facilities of Carpenter, another person, within the meaning and subject to the requirements of Section 203 of the Federal Power Act.

(5) The proposed acquisition of Carpenter's electric facilities by Penelec and Penn Power, as described above, upon the terms and conditions specified in the application and subject to the provisions of this order, will be consistent with the public interest, as expressed in Section 203 of the Act, for the reasons set forth in the recital above.

(6) Neither Penelec nor Penn Power is subject to a requirement of the Public Utility Holding Company Act of 1935 or of a rule, regulation, or order thereunder which would exempt them, pursuant to Section 318 of the Federal Power Act, from the requirements of Section 203 thereof, as the case may be, with respect to any matter wtih which this order is concerned.

The Commission orders:

(A) The proposed acquisition and merger or consolidation of Carpenter's electric facilities, located in the State of Pennsylvania, by Penelec and Penn

Power, all as described above, are hereby authorized and approved upon the terms and conditions set forth in the application, subject to the provisions of this order.

(B) Penelec and Penn Power shall record the transaction herein authorized and the facilities and properties described above as provided in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees. Penn Power, in disposing of the amount of electric plant acquisition adjustment created upon its books of account by reason of the above-described transactions, shall do so by equal annual charges to Account 425, Miscellaneous Amortization, over a period of 10 years commencing January 1, 1962.

(C) This authorization shall expire unless the transaction herein authorized is consummated within 90 days from the date of issuance of this order.

(D) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any matter whatsoever now pending or which may come before this Commission or any other regulatory body or tribunal.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NO CP61-296

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 19, 1962)

On May 22, 1961, as supplemented on August 28, 1961, El Paso Natural Gas Company (Applicant) filed in Docket No. CP61-296 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of approximately 8.2 miles of 34-inch diameter pipeline loop on the eastern end of its San Juan pipeline system near Applicant's Gallup Compressor Station, McKinley County, New Mexico.

Applicant presently operates, as part of its over-all system, a pipeline extending from the Permian Basin area of Texas to a point known as Valve City, near Gallup, south of the San Juan Basin, northwestern New Mexico; this pipeline is known as the San Juan Crossover. Applicant also operates a pipeline system connecting available gas supplies in the San Juan-Aneth area to Valve City; this system is known as the San Juan Mainline. Applicant proposes herein to loop a segment of the San Juan Mainline located between Gallup Compressor Station and Valve City.

Applicant states that the proposed facilities will allow full utilization of its existing production and gas treating facilities in the San Juan and Aneth areas and that said facilities will make available additional sources of supply in the event casinghead and residual gas supplies from the Permian Basin area become restricted. Further, the proposed facilities will make available additional sources of supply in the event of facility breakdown in other portions of the system.

The proposed facilities will increase the present transport capacity of Applicant's San Juan-Aneth area outlet facilities by approximately 100,000 to 109,000 Mcf of natural gas per day.

Applicant states that the proposed facilities will not increase the transmission or delivery capacity of its over-all transmission system.

The total estimated over-all cost of construction of the proposed facilities is $1,148,000, which cost will be financed from current working funds, supplemented by short-term bank loans as required.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 11, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, El Paso Natural Gas Company, a Delaware corporation having its principal place of business in El Paso, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of January 11, 1944, in Docket No. G–288 (4 FPC 486).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce subject to the jurisdiction of the Commission and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (1), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, El Paso Natural Gas Company, to construct and operate the proposed facilities, as hereinbefore described, all as more fully described in the application, as supplemented, herein, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (1), (c) (3), (c) (4) and (e) of Section 157.20 of such Regulations.

(C) The facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within eight months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

LAKE SHORE PIPE LINE COMPANY, DOCKET NO. CP62-75; PAUL L. BRITTON, JR., OPERATOR, *ET AL.*, DOCKET NO. CI62-333

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 19, 1962)

On September 22, 1961, Lake Shore Pipe Line Company (Lake Shore) and Paul L. Britton, Jr., Operator, *et al.* (Britton), filed, respectively, applications pursuant to Section 7(c) of the Natural Gas Act for certificates of public convenience and necessity authorizing: (1) Lake Shore in Docket No. CP62-75 to construct and operate approximately 2,700 feet of 4½-inch and 1,450 feet of 3½-inch field lines, a meter station, and appurtenant facilities to enable Lake Shore to purchase and receive natural gas produced by Paul L. Britton, Jr., Operator, *et al.*, from the Clinton Sand formation in Conneaut Township, Erie County, Pennsylvania, and (2) Britton in Docket No. CI62-333 to make the above-described sale to Lake Shore from 137 acres (2 producing wells) in Conneaut Township, Erie County, Pennsylvania, pursuant to a gas sales contract dated September 5, 1961. The proposals of Lake Shore and Britton are more fully set forth in their respective applications.

Lake Shore's proposed lines will extend from the wells operated by Britton to a point of connection with the facilities of East Ohio Gas Company (East Ohio) in Monroe Township, Ashtabula County, Ohio, at which point the proposed meter station will be constructed. The estimated cost of the subject facilities is $18,155, to be financed from cash on hand.

The gas transported through the subject facilities will be sold and delivered to East Ohio under Lake Shore's existing Rate Schedule E-1 as "excess gas."

Concurrently with the certificate application in Docket No. CI62-333, Paul L. Britton, Jr., Operator, *et al.*, filed the aforementioned gas sales contract as an initial rate schedule to cover the proposed service. The contract provides for an initial rate of 27.0 cents per Mcf at 15.025 psia.

Temporary authorization was issued to each applicant on November 15, 1961.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 11, 1962, respecting the matters involved in and the issues presented by the applications in this proceeding. No petition to intervene or protest to the granting of the applications has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Lake Shore Pipe Line Company, an Ohio corporation having its principal place of business in Cleveland, Ohio, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of February 13, 1951, in Docket No. G-1236 (10 FPC 22).

(2) Applicant, Paul L. Britton, Jr., Operator, *et al.*, upon commencement of the service hereinafter authorized, will be engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission, and will therefore, be a "natural-gas company" within the meaning of the Natural Gas Act.

(3) The facilities to be constructed by Lake Shore, as hereinbefore described and as more fully described in the application in Docket No. CP62-75, are pro-

posed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Lake Shore's existing pipeline system and the construction and operation thereof by Lake Shore are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The sale of natural gas by Britton to Lake Shore, as hereinbefore described and as more fully described in the application in Docket No. CI62–333, will be made for resale in interstate commerce, subject to the jurisdiction of the Commission, and such sale by Britton, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) Lake Shore and Britton, respectively, are able and willing to do the acts and perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(6) The construction and operation of the facilities proposed by Lake Shore in Docket No. CP62–75 and the sale of natural gas proposed by Britton in Docket No. CI62–333, together with the construction and operation by Britton of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Lake Shore Pipe Line Company to construct and operate the facilities hereinbefore described, all as more fully described in the application in Docket No. CP62–75, for the transportation and sale of natural gas in interstate commerce as therein set forth, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations.

(C) The time within which the facilities authorized in paragraph (A) above shall be completed and placed in actual operation is hereby fixed at six months from the date on which this order issues.

(D) A certificate of public convenience and necessity be and the same is hereby issued authorizing the sale by Paul L. Britton, Jr., Operator, *et al.*, to Lake Shore Pipe Line Company of natural gas in interstate commerce for resale, together with the construction and operation by Britton of any facilities subject to the jurisdiction of the Commission necessary therefor, as hereinbefore described and as more fully described in the application in Docket No. CI62–333.

(E) The certificate granted in paragraph (D) above is not transferable and shall be effective only as long as Paul L. Britton, Jr., Operator, *et al.*, continues the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations, and orders of the Commission thereunder.

(F) The grant of the certificate in paragraph (D) above shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or of Section 154 of the Commission's Regulations thereunder requiring the filing of a rate schedule for the service herein authorized, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against Britton. Further, our action in this proceeding shall not foreclose nor prejudice any future proceedings or objections relating to the operation of any price or related provision in the gas purchase contract herein involved.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP62-78

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 19, 1962)

On September 26, 1961, Northern Natural Gas Company (Applicant) filed in Docket No. CP62-78 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the delivery of natural gas on a firm basis to Minnesota Mining and Manufacturing Company (Minnesota), an existing interruptible customer.

Minnesota manufacturers chemicals, lithograph plates and reflective tapes at its Chemolite Plant in Washington County, Minnesota. Applicant states that Minnesota has several different heating processes that require closely controlled combustion conditions, and that firm service would be more advantageous than interruptible service since Applicant's curtailment procedure would result in a change of fuels many times during a heating season and would affect the efficiency of fuel use as well as plant operation if the heating processes were not closely controlled.

Pursuant to a gas sales agreement, dated September 11, 1961, Applicant will deliver, through its Peoples Division, up to 720 Mcf per day of firm gas to Minnesota. Applicant states that Minnesota will continue to purchase small volumes of interruptible gas when the same are available.

Peoples Division will provide the firm volumes to Minnesota from its existing authorized contract demand in its Billing Group 5.

The combined firm and interruptible annual sales to Minnesota are estimated to be 196,000 Mcf; of that amount 4,600 Mcf are interruptible volumes.

Minnesota will pay Applicant's Peoples Division a demand charge of $4.25 per Mcf of contract demand per month in addition to a commodity charge of 34 cents per Mcf for the firm gas.

No new facilities will be required to render the proposed service.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 8, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the

application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Northern Natural Gas Company, a Delaware corporation having its principal place of business in Omaha, Nebraska, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G–280 (3 FPC 967).

(2) The proposed transportation and delivery of natural gas hereinbefore described, as more fully described in the application in this proceeding, are to be made in interstate commerce, subject to the jurisdiction of the Commission, and are, therefore, subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The proposed transportation and delivery of natural gas by Applicant, through its Peoples Division, to Minnesota are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), and (c) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Northern Natural Gas Company, to transport and deliver to Minnesota, through Applicant's Peoples Division, up to 720 Mcf of natural gas per day on a firm basis, as hereinbefore described, all as more fully described in the application herein, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), and (e) of Section 157.20 of such Regulations.

(C) The transportation and delivery of natural gas hereby authorized shall commence as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 6 months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP61-332

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 19, 1962)

On June 19, 1961, as supplemented on August 23, 1961, Northern Natural Gas Company (Applicant) filed in Docket No. CP61-332 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of measuring and regulating facilities and the delivery of firm and interruptible volumes of natural gas to the Brockway Glass Company (Inc.) (Brockway) for use in Brockway's new manufacturing plant located near Rosemont, Minnesota.

Pursuant to a gas sales agreement, dated May 23, 1961, Applicant by October, 1962, will sell and deliver, through its Peoples Division, to Brockway, and Brockway shall purchase up to 1,600 Mcf of firm gas per day. All gas purchased over and above the daily contract demand will be sold as interruptible volumes.

The combined firm and interruptible sales are estimated to total 351,600 Mcf in the fist year and 619,300 Mcf in the second and third years. The firm volumes of natural gas to be delivered to Brockway will be provided from Peoples Division's authorized contract demand with Applicant in Billing Group 5; the interruptible volumes will be delivered as permitted under Applicant's FPC Gas Tariff.

Brockway will pay to Peoples Division a demand charge of $4.25 per Mcf of contract demand per month in addition to a commodity charge of 30.5 cents per Mcf of gas delivered.

Applicant states that the proposed service will provide Brockway with a direct natural gas supply for use as a fuel in two furnaces producing both flint and amber glass. Applicant indicates that firm gas is required because the high degree of control necessary in glass production does not lend itself to the interruption required by conversion to a standby fuel.

The cost of Applicant's proposed facilities is estimated to be $23,600, which cost will be financed from general funds.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 8, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Northern Natural Gas Company, a Delaware corporation having its principal place of business in Omaha, Nebraska, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G-280 (3 FPC 967).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportation and delivery of natural gas in interstate commerce, subject to the jurisdiction of the Commission and the construction and operation thereof by Applicant are

subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities and the proposed transportation and delivery of natural gas by Applicant, through its Peoples Division, to Brockway are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Northern Natural Gas Company, to construct and operate the proposed facilities and to transport and deliver to Brockway Glass Company, Inc., through Applicant's Peoples Division, up to 1,600 Mcf per day of firm natural gas and such interruptible volumes of natural gas as may be permitted under Applicant's FPC Gas Tariff, as hereinbefore described, all as more fully described in the application, as supplemented, herein, upon the terms and conditions of this order. Total deliveries of firm and interruptible gas to Brockway shall not exceed Northern's estimate of 619,300 Mcf per year.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations.

(C) The facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 6 months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SINCLAIR OIL & GAS COMPANY, ET AL., DOCKET NO. RI61-547

ORDER PERMITTING FILING OF SUPERSEDING RATE SCHEDULE ALLOWING WITHDRAWAL OF SUPPLEMENT TO SUPERSEDED RATE SCHEDULE AND TERMINATING PROCEEDING

(Issued January 19, 1962)

On December 21, 1961, Sinclair Oil & Gas Company (Operator), *et al.* (Sinclair Operator) tendered for filing a renegotiated rate increase designated as Sinclair

Operator's FPC Gas Rate Schedule No. 230, and Supplement No. 1 and 2 thereto, to supersede Sinclair Gas & Oil Company, *et al.* (Sinclair) FPC Gas Rate Schedule Nos. 20 and 21, and requested withdrawal of the related Supplement No. 2 to Sinclair's FPC Gas Rate Schedule No. 20, and termination of the proceeding in Docket No. RI61–547.

Sinclair Operator proposes to supersede Sinclair's FPC Gas Rate Schedule Nos. 20 and 21, under which the contract rates are 7.5 cents and 6.0 cents per Mcf, respectively, at 15.025 psia, by submitting a renegotiated contract and notice of change providing a rate of 9.0 cents per Mcf for gas sold to North Central Gas Company from the Sand Draw and Muskrat Field, Fremont County, Wyoming. The increases, 1.5 cents and 3.0 cents per Mcf, for gas previously sold under Sinclair's FPC Gas Rate Schedule Nos. 20 and 21, respectively, total $60,943 annually.

The term of the contract[1] comprising Sinclair's FPC Gas Rate Schedule No. 20 ended on July 1, 1957. Sinclair and the purchasers have executed a cancellation of the contract comprising Sinclair's FPC Gas Rate Schedule No. 21, to be effective contemporaneously with the effective date of the superseding rate schedule. By letter to the Commission dated December 26, 1961, the Wyoming Public Service Commission has advised that it has found the superseding contract to be proper in form and content and in the public interest.

Sinclair Operator requests that the 30-day notice requirement provided in the Commission's Regulations under the Natural Gas Act be waived to permit the proposed increase to become effective January 1, 1962.

By order issued June 28, 1961, in Docket No. RI61–547, Supplement No. 2 to Sinclair's FPC Gas Rate Schedule No. 20 was suspended until September 2, 1961, but has not been made effective subject to refund.

The renegotiated rate increase proposed by Sinclair Operator is below the applicable area price level set forth in the Commission's Statement of General Policy No. 61–1, as amended (18 CFR, Chapter I, Part 2, Section 2.56).

The Commission finds:

Good cause exists for permitting the filing of Sinclair Operator's superseding rate schedule, and the supplements thereto, to allow the withdrawal of Sinclair's superseded supplement, and for terminating the above-designated proceeding. Good cause has not been shown for permitting waiver of 30-day notice required by the Commission's Regulations under the Natural Gas Act.

The Commission orders:

(A) Supplement No. 2 to Sinclair's FPC Gas Rate Schedule No. 20 is hereby permitted to be withdrawn.

(B) Sinclair Oil & Gas Company (Operator), *et al.* Gas Rate Schedule No. 230 and Supplement Nos. 1 and 2 thereto, are accepted for filing to be effective January 21, 1962.

(C) The proceeding in Docket No. RI61–547 is hereby terminated.

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[1] Supplement No. 2 to Sinclair's FPC Gas Rate Schedule No. 20 reflects a proposed increased rate of 13 cents per Mcf based on a unilateral filing by Sinclair subsequent to the expiration of the contract.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SUNRAY MID-CONTINENT OIL COMPANY, DOCKET NO. RI62-196

ORDER DENYING MOTION FOR RECONSIDERATION

(Issued January 19, 1962)

On December 28, 1961, Sunray Mid-Continent Oil Company (Sunray) filed a motion for reconsideration[1] of the Commission's suspension order issued December 1, 1961, in the above-entitled proceeding. By that order, Supplements No. 14 to Sunray's FPC Gas Rate Schedule Nos. 20 and 53, respectively, were suspended until May 2, 1962 and until such further time as they are made effective in the manner prescribed by the Natural Gas Act. The above-designated supplements relate to two renegotiated rate increases to a level of 14.6 cents per Mcf at 14.65 psia for sales by Sunray to United Gas Pipe Line Company (United) in North McFaddin, Keeran, and North Keeran Fields, Victoria County, Texas (Railroad District No. 2).

The contract comprising Sunray's FPC Gas Rate Schedule No. 53 did not contain any favored-nation provision and neither rate schedule involved herein contained any price redetermination provision. Sunray contends, however, that a favored-nation provision was contained in its FPC Gas Rate Schedule No. 20 and has now been eliminated by amendment of the contract. Sunray points to the letter amendments of December 23, 1952, and January 21, 1953, designated as Supplement Nos. 4 and 5 to Sunray's FPC Gas Rate Schedule No. 20, which were filed on November 10, 1954, in support of its position that its FPC Gas Rate Schedule No. 20 contained a favored-nation provision. Examination of these letter amendments discloses that such amendments represented unilateral action by United, the buyer, to pay Sunray the same price United was paying to Gulf Oil Corporation (Gulf) in the same field, in the event that Gulf's price was higher than Sunray's contractual price. It does not appear from the contents of the letter that there was any consideration by the seller for the promise made by the buyer to pay a higher price. Indeed, the letter amendment of December 23, 1952 provides that, upon notice, United could terminate its agreement to pay Sunray the same price that it was paying Gulf. We recognize, of course, that Supplement No. 13 to Sunray's FPC Gas Rate Schedule No. 20, a notice of change in rate tendered for filing by Sunray on the basis of the above-mentioned letter amendments, was accepted for filing and permitted to go into effect on June 11, 1959, the first day after expiration of the required 30 days' notice. Nevertheless, because of the lack of consideration by the seller, it appears that the so-called letter amendments did not constitute a valid contractual favored-nation provision. Accordingly, Sunray's FPC Gas Rate Schedule No. 20 did not contain a valid contractual favored-nation provision.

Sunray in its motion for reconsideration requests that the Commission set aside its order of December 1, 1961, insofar as applicable to the above-entitled

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[1] The document filed by Sunray was entitled an "Application for Rehearing and Reconsideration." Although an application for rehearing of an interlocutory order may not properly be filed (Section 1.30(e) of the Rules), the document was accepted for filing as a motion for reconsideration pursuant to Section 1.12 of the Rules.

proceeding and that the Commission declare that Supplements No. 14 to Sunray's FPC Gas Rate Schedule Nos. 20 and 53, respectively, became effective as of December 2, 1961. In support thereof, Sunray states that its proposed rate increases comply with the standards set forth in the Second Amendment to the Commission's Statement of General Policy No. 61–1. Sunray contends that its FPC Gas Rate Schedule No. 20, as supplemented, fully complies with the Second Amendment, and that its FPC Gas Rate Schedule No. 53, as supplemented, in all material respects complies with the Second Amendment. Sunray claims that the important substantive consideration involved in the Second Amendment is that the contract, after amendment, does not contain favored-nation or price-redetermination provisions. Sunray also points out that the Commission, by order issued April 20, 1961, in the proceeding in Docket No. G–14758 involving Texas Gulf Producing Company under the same circumstances as involved herein decided that the Second Amendment was applicable to the increased rates involved in that proceeding.

By the Second Amendment to Statement of General Policy No. 61–1 issued December 20, 1960, 24 FPC 1107, the Commission amended its Statement of General Policy No. 61–1, issued September 28, 1960, 24 FPC 818, to provide in pertinent part:

> *For rate schedules from which favored-nation and price-redetermination provisions have been eliminated*, the area price level for increased rates for natural gas sales by independent producers in Texas District Nos. 2, 3, 4, and 6 is 14.6 cents per Mcf at 14.65 psia, provided, however, that any escalations contained in such rate schedules shall not take effect prior to February 5, 1963, further escalations shall not take effect at less than five-year intervals from the effective date of the initial escalation, and the increase in rate for such escalation shall not exceed one cent per Mcf. (Emphasis supplied.)

As previously mentioned, Sunray's subject contracts have never contained price-redetermination or favored-nation clauses. Accordingly, it is clear that the proposed increased rates of Sunray involved herein do not come within the specific provisions of the Second Amendment to Statement of General Policy No. 61–1 set forth above, because Sunray has not eliminated any favored-nation or price-redetermination provisions from its contracts. In exercising our suspension powers, it is our purpose to avoid, in individual cases, any future deviations from the general policies which have been declared.

In view of the foregoing, we reaffirm our position, as set forth in the order of December 1, 1961, that the proposed increased rates of Sunray exceed the applicable area price level of 14.0 cents per Mcf. We therefore conclude that the discretionary power to suspend proposed increased rates was reasonably exercised and that we should not alter our prior order.

The Commission finds:

Sunray's motion for reconsideration filed on December 28, 1961, should be denied.

The Commission orders:

Sunray's motion for reconsideration filed on December 28, 1961, is hereby denied.

CONTINENTAL OIL COMPANY, DOCKET NO. G–11024; THE ATLANTIC REFINING COMPANY, DOCKET NO. G–11034; CITIES SERVICE PRODUCTION COMPANY, DOCKET NOS. G–11046, G–15330; TIDEWATER OIL COMPANY, DOCKET NO. G–11049.

OPINION AND ORDER ISSUING PERMANENT CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY UPON REMAND

(Issued January 22, 1962)*

Syllabus

1. Determination of initial rates on basis of field prices adjusted upward for increases in drilling costs found inappropriate; since field prices were not found equivalent to cost, it was not proper to apply percentage escalation derived from cost factors to a base derived from field prices. P. 100.
2. Question of "in lineness" should be determined as of 1956 contract date using prevailing field prices not affected by initial prices courts have called into question; otherwise CATCO would be enriched because of procedural delays. P. 100.
3. Commission notes that method used here (*Supra*—note 2) would not be appropriate where area price levels are applicable or where area rate proceedings have been held with resulting elimination of price problem. P. 100.
4. A sale of gas would not meet test of public convenience and necessity if price at time contract was made was not "in line" with other prices in area. P. 100.
5. Under instant circumstances, price is not "in line" as of given time if it is highest or in highest group of prices theretofore paid; Commission finds that price not in excess of 18½ cents would be "in line" for CATCO sales, although higher than majority of 1956 prices. P. 102.
6. Commission *reaffirms* and *adopts Phillips* case economic factor of 4, as sufficient in this certificate case, for determining Continental's unit cost of exploring for gas as opposed to oil; although on proper record in rate case a different factor might be justified. P. 103.
7. In allocating production cost Commission uses gross revenues method; it not seeming unreasonable to utilize relationship between price CATCO expected to get for gas and price it did get for liquids. P. 104.
8. No contentions being made that after taking into account statutory deductions Continental would pay any Federal income taxes, no "actual taxes" were included in cost of service computation. P. 105.
9. CATCO *allowed* overall rate of return of 11 percent. P. 106.
10. Noting that proof of reserves should ordinarily be made in producer cases, Commission finds CATCO reserves sufficient. P. 109.
11. CATCO permitted to continue collection of additional 1.5 cents per Mcf on Zone 3 production for partial reimbursement of Louisiana Severance tax, subject to refund should Zone 3 be adjudicated to lie within Federal jurisdiction. P. 109.
12. Provisions of CATCO contracts would not trigger existing favored nation clauses in Tennessee's other contracts because Cameron area is outside TGT supply area; nor would any other company's contracts be triggered. P. 109.

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*Designated Commission's Opinion No. 351; Initial decision appears on p. 115. Order granting motion for stay, issued March 12, 1962; order issued March 22, 1962 denying rehearing and clarifying opinion, 27 FPC 498 and 592, respectively.

See order approving settlement, 28 FPC 1090.

13. CATCO contention that no refund requirement existed until issuance of mandate by the Third Circuit is *rejected;* if permitted to file 18½ cent rate prospectively only, CATCO would retain portion of rate found unlawful, Supreme Court's decision and subsequent hearings would be rendered in part futile, and CATCO would be unjustly enriched. P. 109.
14. Requiring restitution of difference between 21.4-cent rate and 18½-cent rate *found* reasonable condition of issuance of permanent certificates to CATCO companies under provisions of Section 7(e) of the Natural Gas Act. P. 110.
15. Upon *remand* from Supreme Court, Commission issues permanent certificates of public convenience and necessity under Section 7 of the Natural Gas Act. P. 111.

Bruce R. Merrill and *Robert C. Hawley* for Continental Oil Company.

Bernard A. Foster, Jr., William R. Dotson, Charles B. Ellard, and *Edward J. Kremer, Jr.,* for The Atlantic Refining Company.

Bernard A. Foster, Jr., Cecil Cammack, Gentry Lee, and *R. J. Leithead* for Cities Service Production Company.

Clyde E. Wilbern, Robert O. Koch, Raybourne Thompson, and *J. E. Atwell* for Tidewater Oil Company.

Jack Werner, William W. Bedwell, L. R. Pankonien, Harry S. Littman, and *William C. Braden, Jr.,* for Tennessee Gas Transmission Company.

Edwin F. Russell, Harry G. Hill, Jr., and *Robert Lisle* for The Brooklyn Union Gas Company.

James O'Malley, Jr., and *John A. Lodge* for Consolidated Edison Company of New York, Inc.

Edward M. Barrett, David K. Kadane, J. David Mann, Jr., S. G. Miller, Henry P. Sullivan, John E. Holtzinger, Jr., and *Bertram D. Moll* for Long Island Lighting Company.

Edward S. Kirby, William R. Duff, James R. Lacey, John McDonald, and *J. Harry Mulhern* for Public Service Electric and Gas Company (New Jersey).

Barbara M. Suchow and *Kent Brown* for Public Service Commission of the State of New York.

Herbert E. Squires for Pennsylvania Public Utility Commission.

John Paul Geneau, Robert W. Perdue, and *Robert L. Russell* for Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SWIDLER, *Chairman:*

This is a certificate proceeding before the Commission on remand by the Supreme Court.[1] Previously the Commission had granted certificates to Continental Oil Company, The Atlantic Refining Company, Cities Service Production Company and Tidewater Oil Company, collectively called CATCO, for the sale of gas to Tennessee Gas Transmission Company from offshore Louisiana areas. The Commission, in the final order of three, accepted the proposed initial price of 21.4 cents per Mcf at 15.025 psia[2] without conditions, and the Supreme Court reversed it for lack of record support. After a second series of hearings, and exchange of briefs, the examiner issued his decision on August 14, 1961, and exceptions were filed by CATCO, Interveners,[3] the Public Service Commission of

[1] *Atlantic Refining Co.* v. *F.P.C.,* 360 U.S. 378.

[2] Unless otherwise noted, unit prices and volumes in this opinion are on a basis of 15.025 psia.

[3] Long Island Lighting Company, Public Service Electric and Gas Company, and The Brooklyn Union Gas Company.

New York (PSC), the Pennsylvania Public Utility Commission, and the staff. The principal question before the Commission is the initial price that is required by the public convenience and necessity in accordance with the provisions of Section 7(e) of the Natural Gas Act.

Procedural and Factual Background

Each of the four applicants owns a quarter interest in a number of gas leases located 20 to 30 miles off the coast of Louisiana in the Gulf of Mexico.[4] Thirty-nine wells have been drilled, of which 13 are dry holes, 3 are dry gas wells and 23 are gas-condensate wells. The offshore operations are conducted from seven platforms. CATCO owns the platforms, wells, separators and meters but no pipelines. To connect with the offshore wells, Tennessee has built some 46 miles of 26-inch line from its main line at Kinder, Louisiana, to the shore, and some 60 miles of line on the Gulf bottom to the platforms.

In August of 1956, CATCO contracted to sell the production of these leases to Tennessee for a base price of 21.4 cents per Mcf. While provision is made for reimbursement by Tennessee of part of the Louisiana taxes, there will probably be no state taxes because the land underlying the leases appears to be located in the federal domain. Deliveries to Tennessee began in July of 1958.

Turning to the procedural aspects of these proceedings, the original applications were filed by CATCO in September of 1956 and hearings were held on February 28 and March 1, 1957. After an examiner's decision the Commission issued an order April 22, 1957, granting CATCO temporary certificates but denying permanent certificates because the rate had not been shown to be in the public interest (17 FPC 574); on May 20, 1957 (17 FPC 732) the Commission granted permanent certificates on the ground that CATCO would not accept temporary certificate, but conditioned the initial price at 18 cents per Mcf, to include an allowance of one cent for the supposed Louisiana gathering tax; and on June 24, 1957 (17 FPC 880) after oral argument on rehearing the Commission removed the price condition because of the need for the gas and because it appeared that CATCO would not accept conditioned certificates. The final action, therefore, was to grant a certificate on the terms for which application had been made.

The PSC and Interveners initiated review and the order was vacated by the Court of Appeals, *P.S.C. of New York* v. *F.P.C.*, 257 F. 2d 717 (CA3); this action was affirmed by the Supreme Court in *Atlantic Refining Co.* v. *F.P.C.*, 360 U.S. 378, on a finding that the record did not show the proposed price was required by the public convenience and necessity. The vacation and remand was issued by the Court of Appeals on November 16, 1959, and on November 17, 1959, CATCO was granted temporary authorization effective upon issuance of the Court's mandate.

Meanwhile CATCO filed applications for the sale of additional gas from the East Cameron area. By order issued February 16, 1959, in Docket No. G–15330 the Commission granted a certificate to Cities conditioned so that the initial price should agree with the price finally resulting from these proceedings. A temporary certificate was issued to Atlantic on July 14, 1958, in Docket No. G–15374, but this was replaced by the temporary certificate issued to the Company on November 17, 1959 in Docket No. G–11034, and the earlier authorization was rescinded.

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[4] Originally the leases were located in the East Cameron, West Cameron and Vermilion areas; a number of leases have since been surrendered because not commercially productive including all of those in the Vermilion area.

On December 11, 1959, following receipt of the court's mandate the Secretary reopened the hearing, and, after a prehearing conference, hearings commenced March 15, 1960 and concluded January 19, 1961. Briefs were filed and the examiner issued his decision August 14, 1961.

Briefly, the examiner proposed issuing certificates to CATCO conditioned on an initial price of 19.92 cents per Mcf determined as of the date of the original certificates, June 24, 1957. In doing so he determined reserves on the basis of the record in the reopened proceeding and arrived at 1,244,363 Mmcf representing recoverable reserves as of January 1, 1960. With respect to field prices he concluded that none of the contract prices available in evidence could be directly compared with the proposed price because of the size of the CATCO reserves. On the basis of the evidence he determined a base price of 17 cents representing the weighted average initial price under South Louisiana contracts dated 1953–1955. He adjusted this base price upward by a factor of 17.2 percent representing the increase in per foot costs of drilling and equipping productive offshore wells in Louisiana from 1954 to 1956. This resulted in the cost of 19.92 cents per Mcf (15.025 psia) before taxes or transportation costs. The examiner considered the cost of service evidence introduced by CATCO, the Interveners and the staff. As discussed below, he found difficulties with the several methods but, using a 16.2 percent rate of return, found that the staff method resulted in a cost per Mcf of 20.58 cents as adjusted by him to 1957 and substantially confirmed his 19.92 cents per Mcf result. He ordered refunds to Tennessee from the date of initial delivery.

The exceptions of CATCO, Interveners, the New York and Pennsylvania Commissions and the staff were filed October 30 and 31, 1961.

The Methods To Be Followed

Our principal guide in making a determination of an initial price here is the Supreme Court's opinion in these proceedings. The Court points out that the Act does not require a determination of just and reasonable rates in a section 7 producer proceeding as it does in one under section 4 or section 5, nor is a "just and reasonable" rate hearing prerequisite to the issuance of producer certificates. Nevertheless, the Court requires careful scrutiny of proposed initial prices. The proposals of the applicants must be supported by evidence showing their necessity to the present or future public convenience and necessity before permanent certificates are issued. The Court said that where "the proposed price is not in keeping with the public interest because it is out-of-line or because its approval might result in a triggering of general price rises or an increase in the applicants' existing rates by reason of 'favored nation' clauses or otherwise, the Commission in the exercise of its discretion might attach such conditions as it believes necessary." [5] The Court recounted the instances where statements made by the Commission in support of its approval of the 21.4 cent per Mcf initial price lacked record support.

The question immediately arises as to the approach to be used to a determination of the proper initial price. The record contains evidence of field prices in the Southern Louisiana area and cost of service evidence, which, however, falls short of that usually found requisite in a rate case. As noted, the examiner's basic method was to find a price based on the field price evidence for the years 1953–1955 in the amount of 17 cents and to adjust it upward by the increase in drilling costs between that period and 1956 to arrive at 19.92 cents per Mcf as the initial price to be allowed. He used the cost of service evidence, principally as presented by the staff, in confirmation of his result, but made a number of

[5] 360 U.S. at p. 391.

important adjustments. His determination of recoverable reserves did not appear to be utilized by him in reaching his result on the initial price.

As will be seen, we agree with the examiner that the initial price should be determined as of a past period. However, we agree with the Interveners and PSC that it was not appropriate to determine an initial rate on the basis of field prices adjusted upward for increases in the cost of drilling. The field prices were not shown to be equivalent to cost. Therefore, it was not proper to apply a percentage escalation derived from cost factors to a base derived from field prices. Furthermore, the data on drilling costs in 1954 were derived from one source while the data for 1956 were derived from another source. We shall rather determine the "in line" price using the field price evidence available in the record. This evidence includes prices at the time of the sale in 1956, and before, which were not affected by initial prices which the courts have called into question.[6] Like the examiner, we shall then compare the "in line" price with the cost of service evidence. Before going further, we may note that the method used here would not be appropriate where area price levels announced by us are applicable or where area rate proceedings have been held with the resulting elimination of the price problem. We shall now consider the question of the price line.

The Price Line

The first question is as to the date of the "in lineness". This question should be determined as of a past date; otherwise CATCO would be enriched because of procedural delays. The sale was to be made under contract of August 1956. While our previous determination reversed by the Supreme Court was made in June of 1957 and deliveries did not begin until July of 1958, we think that the question of "in lineness" should be determined as of 1956. It was then that the parties agreed on a price. The Supreme Court was thinking of the origination of price levels by contract when it stated that "New price plateaus will thus be created as new contracts are made and unless controlled will result in 'exploitation' at the expense of the consumer"[7] and referred to the proposed "contract price" as higher than any paid by Tennessee.[8] In our opinion a sale would not meet the test of public convenience and necessity if the price at the time the contract was made was not "in line" with other prices in the area.

The CATCO opinion has not defined what is meant by a price being "in line", nor have the Courts of Appeals done so with any precision.[9] The Ninth Circuit case states that the "line" referred to in CATCO "may properly be referenced to relevant existing producer prices under which substantial amounts of natural gas move in interstate commerce." This case also points out that the prices must be comparable.

Before going into the comparative price evidence it is necessary to examine the situation with respect to Louisiana taxes. The Louisiana gathering tax referred to in our prior order (17 FPC 732, 734) was suspended by the Louisiana Legislature on August 1, 1958.[10] The prior Louisiana severance tax of .3 cents

[6] See cases cited in footnote 9 below.

[7] 360 U.S. at p. 390.

[8] 360 U.S. at p. 393.

[9] See *United Gas Improvement Co.* v. *F.P.C.*, 283 F. 2d 817 (CA9), certiorari denied 365 U.S. 881; *P.S.C. of N.Y.* v. *F.P.C.*, 287 F. 2d 146 (CADC), certiorari denied 365 U.S. 880; *The United Gas Improvement Co.* v. *F.P.C.*, 287 F. 2d 159 (CA10); *The United Gas Improvement Co.* v. *F.P.C.*, 290 F. 2d 133 (CA5), certiorari denied, 368 U.S. 823, decided October 9, 1961.

[10] Louisiana Acts 1958, Ex. Sess. No. 3 § 1, Louisiana Statutes Annotated 47: § 681.1 after the gathering tax had been declared unconstitutional under the Louisiana Constitution, *Bel Oil Corp.* v. *Fontenot*, 238 La. 1002, 117 SO 2d 571.

per Mcf was increased on December 1, 1958 to 2.3 cents per Mcf, but is not applicable to the most seaward area known as Zone 4 in which are located part of the CATCO leases. With respect to the Zone 3 production after December 1, 1958, Tennessee has paid a 1.5 cents per Mcf severance tax reimbursement, which is being held in suspense by CATCO and will be refundable to Tennessee if the Federal Government is ultimately determined to be the owner of the Zone 3 lands. In *United States* v. *Louisiana*, 363 U.S. 1, 79, it was held that Louisiana is "entitled to submerged-land rights to a distance no greater than three geographical miles from its coastlines, wherever those lines may ultimately be shown to be." We agree with CATCO that it appears unlikely that any of the Cameron production is subject to Louisiana tax, although the question is not yet free from doubt. Therefore, we think it proper to compare the Cameron area tax-free base price with base prices elsewhere, but in the order we shall make provision for the contingency that state taxes are applicable.

The applicants, as well as other parties, have put in evidence a considerable amount of price data in order to overcome the deficiencies in the record found by the Supreme Court. However, most of the price evidence dating from the time of the CATCO contracts and earlier relates necessarily to onshore sales, which differ in some degree from the sales made here from platforms in the Gulf of Mexico. Nevertheless, we believe them useful in establishing the price line in the area. The Supreme Court considered them relevant in observing how prices had vaulted from one level to another.

In general the evidence shows that while there were prices of 20 cents or more in Southern Louisiana as early as 1952, there were few prices above a basic rate of 18 cents before the CATCO contracts. Interveners show that out of 290 contracts dated January 1, 1950, to December 31, 1956, only 20 had base prices of 20 cents or above and only 22 more had base prices of 18 cents or above. In the year 1956, 4 were in the range 21–21.49 cents per Mcf, 4 were 20–20.49, 12 were 18–18.99, 17 were 17–17.99, 33 were 16–16.99 and 4 were under 16 cents. CATCO points out that upon cross examination certain errors were revealed in Interveners' study. These alleged errors relate to the omission or inclusion of certain contracts, particularly the duplicative inclusion of contracts having multiple sellers where each one had filed a separate rate schedule. While there appear to have been some errors, the general picture is the same even on the basis of the evidence presented by CATCO.

CATCO plots on a graph the South Louisiana contracts from 1947 through 1959 showing numbers, initial base prices and pipeline buyers. The general pattern of this study up until the end of 1955 portrays a few contracts on the 20-cent level in 1952, 1953 and 1955, with the other contracts ranging down to about 6 cents (in 1947). Beginning with 1952 there appear a number of contracts in the 16-cent range; in 1953 in the 18-cent range and in 1955 in the 17-cent range. In 1956 the number of contracts proliferated considerably. Numbers appear in the 16-, 17- and 18-cent range, six appear around 20 cents and 4 around 22 cents. In 1957, 1958 and 1959 many contracts appear in the range between 20 and 23 cents, but even in those years there were many contracts around 18 cents and below and a scattering below 15 cents. More specifically, CATCO shows that in the years July 1, 1954 to June 30, 1956, out of a total of 68 contracts, 12 were above 18 cents, 47 were in the range 16 cents through 18 cents, and 9 were below 16 cents.

The average of the initial base prices for contracts dated during the respective quarters of 1956 weighted by 1958 volumes are as follows: 17.00 cents, 18.22 cents, 17.38 cents, 16.65 cents. The weighted average prices actually paid for 1958 deliveries under contracts of the year 1956 was 18.59 cents for interstate gas and

16.87[11] cents for intrastate gas. CATCO has made the point that prices are higher for the larger volumes, but for contracts entered into during the period July 1, 1954 to June 30, 1956, out of a total 1958 volume of 241,215 Mmcf only 63,979 Mmcf were obtained at prices above 18 cents, while the remaining volumes were sold at lower prices. The two largest volumes sold, 61,305 Mmcf and 91,988 Mmcf were sold at 16 and 17 cents, respectively.

The only offshore price brought specifically to our attention was the base price of 17 cents per Mcf found in the CATCO contracts with Tennessee dated January 1956, dedicating the West Delta reserves. This price is not strictly comparable although it does offer some light on prices in the area. In contrast to the Cameron area leases which are 20 to 30 miles from the Coast, the West Delta acreage lies within 10 miles of the shore. The record indicates CATCO was anxious to dispose of the West Delta gas promptly to avoid flaring, and Tennessee was unwilling to pay more than 17 cents for fear of triggering the favored-nation provisions of earlier contracts. While there may have been limitations on Tennessee, it appears that no other pipeline was willing to offer a higher price.

Under the circumstances here involved a price, in our opinion, is not in line as of a given time if it is the highest price or in the highest group of prices theretofore paid. For the year 1956 a contract for 21.4 cents per Mcf is clearly out of line. In our opinion, a price not in excess of 18½ cents would be "in line", although higher than the majority of prices in 1956.

Cost of Service

Although taking the position that it was impossible to determine actual costs in a certificate proceeding and that cost of service evidence was not necessary, Continental, as operator of the Cameron properties, presented such evidence on the basis of the test year 1959 in support of the CATCO application on the assumption that its costs would represent the costs of the other members of the CATCO group. It allocated Cameron area production costs between gas and condensate by the Btu method and derived a unit production cost for gas; and it allocated company-wide exploration costs, also by the Btu method, to arrive at a unit exploration cost. In making these computations it used a rate of return of 14 percent plus an allowance for income taxes without taking advantage of the statutory deductions and reached a cost of gas of 43.67 cents per Mcf.

The Interveners contend that the cost of service presented by Continental is valueless and that a meaningful cost of service cannot be determined for less than company-wide operations. Nevertheless they prepared adjustments to Continental's cost of service presentation using the relative cost method for allocating production costs, the reserves added realization method for exploration costs and an 11 percent rate of return, to arrive at a unit cost of 18.16 cents per Mcf.

The staff followed the same general method as Continental but allocated company-wide exploration costs to gas on the basis of the Btu method modified by the economic factor of 4 as set forth in the *Phillips* case[12] and production costs on the basis of gross revenues. Using a 9 percent rate of return, the staff arrived at a unit cost of service of 17.33 cents per Mcf. With some reservations, the examiner followed the same general method as the staff, but used a 10.2 percent rate of return to arrive at a unit cost of 21.38 cents per Mcf. The ex-

[11] These two unit prices are computed at pressure bases used by the pipeline companies in their FPC Form 2 Reports.

[12] 24 FPC 537, 560; affirmed *State of Wisconsin* v. *F.P.C.*, 303 F. 2d 380, CADC, No. 16175, decided November 30, 1961, *cert.* granted May 14, 1962, 369 U.S. 870.

aminer adjusted his result for capital expenditures made in the years 1958 and 1959, and increases in the cost of drilling and labor to arrive at unit cost of 20.58 cents per Mcf as of 1957.

It is clear enough that the cost of service evidence here is not complete as presented by any of the parties. In the first place the evidence relates to Continental alone and not to the other CATCO companies. Furthermore, it combines Continental's production costs for the Cameron area leases with Continental's system-wide exploration costs. While the incomplete nature of the evidence makes it impossible to make a definite finding as to cost of service, it does provide a basis of comparison with the field prices which may assist us in determining whether the proposed initial price meets the standards of the Act.

The examiner's computation of cost of service appears to be as follows although not set forth in this form:

	Costs allocated to gas	Unit costs (cents)
Production cost:		
Lease expense	$237,302	
Retirements and abandonments	112	
Leasehold depletion	4,906	
Depreciation of Lease and well equipment	91,405	
Amortization of Intangible drilling costs	339,165	
Overhead	114,336	
Total production expense	787,226	
Special facilities depreciation and amortization	6,897	
Production taxes	31,216	
Return at 16.2 percent	817,139	
Total production cost	1,642,478	
Unit cost using the 1959 volume of 10,014,362 Mcf		16.40
Exploration costs:		
Company-wide exploration expense per unit		4.03
Company-wide exploration return per unit (at 16.2 percent)		.95
		21.38
Total exploration cost	498,715	
Total cost of service	2,141,193	

In the first place we do not think that the 1959 cost of service should be adjusted backward to the year 1957, as the examiner did in arriving at 20.58 cents.[13] The year 1959 was the first full calendar year of operation. It is appropriate to compare the initial price with costs from actual operation in the year when they are available without speculating on what they would have been in a previous year. We may now consider the contentions made by the parties in their exceptions.

CATCO objects to the examiner's modifying the Btu method of allocating company-wide exploration costs by the use of the economic factor of 4 utilized in the *Phillips* case. CATCO argues that the nature of the CATCO production requires the use of the straight Btu method and points out that the examiner adopted the Phillips factor "subject to considerable reservation" since there was no record evidence to support it. In the *Phillips* case we allocated the company's exploration costs between oil and gas by the Btu method modified by the factor of 4 to reflect the economic relationships between the two products as discussed fully in our opinion.[14] We reaffirm that method and adopt it for determining Continental's unit cost of exploring for gas as opposed to oil; and this unit cost may then be applied to the gas produced from the Cameron

[13] Or 20.60 cents including an allowance for regulatory expense.
[14] 24 FPC 537, 558–561.

leases. We think that the use of the *Phillips* case factor of 4 is sufficient for the purposes of this certificate case, although on a proper record in a rate case a different factor might be justified.

CATCO also argues that the straight Btu method should have been used to allocate the Cameron area production costs. CATCO contends that this method is appropriate here where the problem is to allocate costs between gas and condensates as it was to allocate costs between gas and liquids at the gasoline plants in *Phillips*, 24 FPC 537, 563–564. The record shows that the condensates are carried in Tennessee's gathering lines to shore and processed in refineries. We can take notice that condensate is not the equivalent of the natural gasoline separated in the Phillips plants, but is rather a light petroleum which can be used for a number of purposes, including the manufacture of chemicals, so that our discussion in the *Phillips* case as to the inapplicability of the straight Btu method (for exploration costs) applies here. In *Phillips* we used the relative cost method based on unit costs abtained from Phillips' 100 percent oil wells. Here we have no 100 percent oil wells or sufficient volumes from the 100 percent gas wells to make the relative cost method possible. It was, therefore, necessary to use the gross revenues method, but merely for the purpose of arriving at a ratio. It does not seem unreasonable to utilize the relationship between the price CATCO expected to get for the gas and the price it did get for the liquids as a basis of allocation.

CATCO also objects to the failure of the staff and the examiner to include, in the amortization of intangible drilling costs shown above in the amount of $339,165 computed on a lease by lease basis, any allowance for two wells allegedly abandoned in 1959. The record shows that as to Lease No. 9830511 the well was completed in 1955 and the intangible drilling costs had been depleted through production to $100,118 as of December 31, 1958. As to Lease No. 9837511 completed in 1957 none of the intangible drilling costs amounting to $262,119 had been written off because the well had been shut-in. The total amount still to be amortized was thus $362,237. CATCO proposed to write the whole amount off in the test year.

We agree with the staff that this amount was non-recurring and should not have been written off in the test year, for such a write-off would give a distorted picture of cost. However, we think that the unamortized amount should be recovered. Alternatively the staff had submitted a study showing the effect of amortizing the intangible well drilling costs for all wells including the two dry wells on an area basis rather than on a lease by lease basis. The area basis of amortization, in our opinion, is the more appropriate because it is not affected by swings of production between the high cost and low cost leases so that it leads to a more stable result. It also takes into account amortization applicable to the two dry holes. It will, therefore, be followed in the computation below. The amortization item, however, is less than shown above for the examiner's computation largely because his estimate of reserves is used rather than Continental's, as will be discussed later, but also because the particular pattern of production in 1959 results in a slightly higher allowance on a lease by lease basis than on the area basis that we find appropriate.

In its cost of service computation, Continental included an allowance for Federal income taxes computed by adding an item representing 108 percent of the amount of return. This would represent taxes without taking into account the statutory deductions for percentage depletion and intangible well drilling costs under Sections 613 and 263 (c) respectively of the Internal Revenue Code. This is, of course, contrary to *El Paso Natural Gas Co.* v. *F.P.C.*, 281 F. 2d 567 (CA5), certiorari denied, 366 U.S. 912, and our treatment in the *Phillips* case.[15]

[15] 24 FPC 537, 568–569.

Apart from this, CATCO objects to the staff and examiner making no allowance for taxes. There is nothing to show and there is no contention made that after taking into account the statutory deductions Continental would pay any Federal income taxes as a result of its producing business in the year 1959. On the other hand, considering the Cameron area properties separately Continental does show in its discounted cash flow study estimated income taxes payable of $561,000 after all deductions for the year 1959 taking into account investment, revenues and expenses over the entire life of the properties. Furthermore, using an 11 percent return CATCO has submitted in its answer brief an "Actual Federal Income Tax Calculation" for Continental in the Cameron area in which it shows the tax applicable to gas production to be $528,114 and applicable to gas exploration to be $54,416.

The latter figures are derived by deducting from return the alleged Cameron area intangible well drilling costs in the amount of $10,516 for the year 1959. However, the cash flow study indicates that the equivalent deduction was much larger in 1958 and prior years, so that due to this deduction and the absence of revenues, except in 1958, there were large tax losses relating to the Cameron properties. The effect of this is that in the early years the Cameron area deductions offset the company's income elsewhere while in 1959 and succeeding years presumably the Cameron area income is in turn offset by deductions from drilling in other areas. However, assuming for the purposes of this cost of service that all of Continental's revenues and deductions arise from the Cameron area, we would also have to assume that under Section 172 of the Internal Revenue Code Continental would carry forward its losses in the years through 1958 to 1959 and succeeding years. It is entirely clear from Continental's cash flow study that any "actual" taxes in 1959 would be eliminated as well as the taxes for several years thereafter. Beyond that what revenues, deductions and taxes are applicable to the Cameron area are entirely speculative. Therefore, we shall include no "actual" taxes in the cost of service computation.

With respect to rate of return the record does not include the extensive financial data usually found in a rate case. Continental, however, did present (1) an exhibit showing the return earned after taxes on book net assets by groups of corporations in a variety of industries; (2) an exhibit showing rates of return earned each year on computed rate bases by ten Class A producers of oil and gas, that is those that produce but do not refine or engage in other activities; (3) testimony by its witness on the risks of the Cameron area operation and the need for a rate of return of 14 percent in addition to the statutory tax benefits.

In the first place we are of the opinion that the return earned by other companies, while it should be taken into consideration, does not constitute a complete rate of return presentation. What is earned by other companies may or may not be reasonable. In rate of return cases we have ordinarily considered earnings-price ratios as reflecting how the money market considers the risk involved, and there are instances where the earnings-price ratios of the companies which are solely producers are less than those of the integrated companies.

The first exhibit shows a rate of return on book net assets for the period 1947–1958 of 21.3 percent for Class A petroleum companies, and 15.5 for Class B petroleum companies, which engage in other activities as well as producing. However, if the year 1958 alone is considered, the rates of return are 12.7 percent and 10.9 percent respectively. Continental is engaged in production, manufacturing and marketing and should be considered a Class B type company for the purposes of the exhibit, although the examiner treats it as a type A company. Furthermore, this first exhibit actually measures return on

equity rather than on the entire capitalization so that the returns shown would have to be adjusted downward to reflect the cost of debt and proportion of debt in the total capitalization in order to reach an overall cost of money.

The second exhibit shows rates of return ranging from 30.99 percent in 1947 to 15.22 percent in 1958 or an average of 21.88 percent. It deals with such a narrow group of successful Class A companies that in our opinion it is not at all persuasive. Therefore, we do not adopt the examiner's use of a 16.2 percent rate of return which was derived by using the average return from this exhibit for the years 1954–1958 and weighting the years more heavily as they approached the test year 1959. Nor do we adopt the staff's rate of return of 9 percent which was merely illustrative. We are fully cognizant of the risks of drilling for gas and the need to encourage continued exploration and production. However, with respect to the peculiar hazards of offshore drilling, we are of the opinion that they are at least in part offset by the opportunity for discovering large reserves, as indeed has proved to be the case. In view of this incomplete record and the fact that this is not a rate case we shall make use for purposes of this case of the overall rate of return we allowed in *Phillips*, namely 11 percent. As set forth in the *Phillips* case the 11 percent return includes an amount in addition to other financial needs designed specifically to provide an incentive for exploration and development. In arriving at this allowance in the *Phillips* case we were, of course, looking at the financial needs of the company as a whole and we do the same here. From the financial viewpoint it would not be proper to consider Continental as though it owned only the Cameron area leases because its ability to raise money is not dependent only on this limited segment of its business.

In order to show that its proposed 21.4 cents price would not yield an excessive return CATCO presented in evidence its discounted-cash-flow analysis. In this study CATCO showed, with respect to the Cameron project, investment, production, revenues, expenses, taxes and return from 1947 through 1982. The study shows, according to CATCO, that the Cameron area properties would yield a return on investment of only 10 percent if the initial price were collected throughout their life and only 11.2 percent with escalations. In our opinion this type of study, dependent heavily on speculation, does not provide a reliable support for the initial price or rate of return. Continental's witness admitted there was room for an appreciable margin for error in a study which requires estimating the rate of production, revenues and expenses for a quarter of a century in the future.

Although not taking any exception on the point CATCO contends that it should be given an allowance for regulatory expense totaling $495,548 as of April 30, 1960 for the four companies. It would amortize Continental's share of such expense over three years to arrive at a cost of $58,306 using an 11 percent return including an allowance for taxes. We agree that reasonable regulatory expense should be allowed, but this is a certificate case and not a rate case in the sense that we could expect that it be repeated every three years. We think that a reasonable treatment would be to amortize Continental's share ($123,887) of the regulatory expense over a period of five years and we have included the resulting amount of $24,777 in the cost of service.

Interveners have made the point in oral argument that the examiner developed with some care a reserve estimate for the Cameron area and then failed to make use of it in the cost of service. In their cost of service computations Continental, the staff and the examiner arrived at a unit cost on the basis of the 10,014,362 Mcf of gas actually produced in the test year 1959. This is, of course, the method ordinarily followed when making use of a test year, for it is appropriate to relate test year costs to test year volumes. We do not agree

with Interveners' contention that the normal deliverability of 13,816,045 Mcf per year [16] based on the examiner's reserve estimates should be used in determining a unit cost, for if this volume were produced, other items in the cost of service would be affected, so that it would be necessary to devise a purely theoretical test year not shown by the record.

Apart from these considerations the question of reserve does affect the cost of service. Continental, the staff and the examiner used Continental's reserve estimates in their computations. The item relating to the amortization of intangible well drilling costs, already discussed in another connection, would be affected, as well as the less important item of depletion. Therefore, it is relevant to consider the issue of reserves.

CATCO presently estimates the initial reserves in place (at 14.73 psia) to be 871,956 Mmcf located in Blocks 62, 64, 71 and 192, in the offshore Cameron area, but in the original hearing it adopted the estimate of Tennessee's witness for Blocks 49 (abandoned), 62, 71 and 192 totaling the larger amount of 1,995,659 Mmcf. Tennessee now estimates initial reserves in place of 1,580,825 for the 62, 64, 71 and 192 Blocks. For the same four blocks the examiner, CATCO and Tennessee estimate recoverable reserves as follows:

Mmcf at 14.73 psia	CATCO	Tennessee	Examiner
Initial recoverable reserves	711,017	1,322,921	1,305,315
Recoverable reserves as of Jan. 1, 1960	650,065	1,261,969	1,244,363
Salable reserves as of Jan. 1, 1960	642,660	1,245,410	1,228,195

The record shows that the major differences between CATCO and Tennessee relate to net pay (thickness of gas bearing formations), areal extent of the reservoirs, porosity values, and connate water content. In important instances, there were unreconcilable differences between the experts for CATCO and Tennessee, and the staff in its brief contended that the recoverable gas reserves of the four fields cannot be determined from the facts and testimony submitted by the parties. The staff, however, advocated using Tennessee's higher estimate to avoid injuring the public. On our part the record does not permit us to arrive at a definite conclusion with respect to these reserves. For the purposes of our comparative cost computation we shall use the examiner's carefully considered estimate, which is close to Tennessee's but somewhat smaller. As can be seen, the item for the amortization of intangible well drilling costs applicable to gas becomes $145,290 on the area-wide basis using the examiner's estimate of reserves.[17] We may note, however, that if we had used CATCO's estimate of reserves the amortization figure would be raised to $289,813 and the final unit cost of service would become 18.86 cents per Mcf at 15.025 psia, still close to the price which we consider to be "in line".

A final factor should be reflected in the price paid by Tennessee. Under its arrangements with the CATCO companies Tennessee carries the gas which it has purchased and the condensates owned by CATCO in its gathering lines from the offshore platforms to the shore of Louisiana. As to transporting its own gas, we see no reason why the cost of such transportation should not be borne by Tennessee, because it is Tennessee's custom to extend pipelines to the gas supplies. We think these transportation costs should be considered to be

[16] This represents Continental's share (¼ of ⅞) of the 20-year average deliverability of 176,504 Mcf per day found by the examiner.

[17] See the computation in Appendices 3 and 1. The record does not supply sufficient information to permit us to adjust the small depletion figure employed by the examiner.

nearer the staff's 4 cents per Mcf based on a period closer to the test year than the examiner's 1.98 cents per Mcf based on developments extending to 1963. A different problem arises with respect to the condensates which are transported to CATCO's Grand Chenier separation station, where they are removed and the gas redelivered to Tennessee. Such transportation in effect is a service performed by Tennessee for Continental and the other CATCO companies, and in a cost calculation a credit should be given Tennessee for an allocated part of the transportation costs. The allocation should be made on the basis of the volumes of gas transported and on the basis of the vapor volumes of the liquids multiplied by an estimated cost factor of 4. This results in an estimated amount of $17,117 [18] applicable to the gas delivered to Tennessee.

On the basis of the foregoing discussion, Continental's cost of service is computed as follows: [19]

	Costs allocated to gas	Unit costs (cents)
Production costs:		
Lease expense	$237,302	
Retirements and abandonments	112	
Leasehold depletion	4,906	
Depreciation of lease and well equipment	91,405	
Amortization of intangible drilling costs	145,290	
Overhead	114,336	
Total production expense	593,351	
Special facilities expense	6,897	
Production taxes	31,216	
Regulatory expense	24,777	
Less: Tennessee's Liquids Transportation Service	(17,117)	
Return at 11 percent	640,767	
Total production cost	1,279,891	
Unit cost using 1959 volume of 10,014,362 Mcf		12.78
Exploration cost:		
Company-wide exploration expense per unit		4.03
Company-wide exploration return per unit (at 11 percent)		.65
Total exploration cost based on Continental's 1959 volume	468,672	
Total cost	1,748,563	17.46

The Initial Rate and Other Matters

It has already been shown that an 18½ cents per Mcf price in 1956 would be "in line" and would represent the price "line" as of the year when the CATCO contracts were made The limited cost of service evidence in this proceeding does not require another result. Our computed cost figure of 17.46 cents per Mcf was reached after ruling against CATCO on a number of disputed points and thus represents a minimum amount. It indicates that an initial price of around 18½ cents would cover the CATCO costs, include an incentive for continued exploration and development either in the Cameron area or elsewhere, and would provide a margin for error on the disputed points, particularly in case the Cameron area reserves were not as great as found by the examiner. In our prior order of May 20, 1957 (17 FPC 732), later changed in our order of June 24, 1957 (17 FPC 880), we prescribed an initial rate of 18 cents per Mcf, including, however, a one cent Louisiana gathering tax supposed to be applicable. On the basis of the present record we are of the opinion that an initial rate of 18½ cents per Mcf will meet the requirements of the public convenience and necessity.

[18] See Appendix 4.

[19] See more detailed computations in attached Appendices 1, 2 and 3.

As noted above it does not appear that CATCO will be liable for state taxes in the offshore areas, but all doubt has not been removed with respect to the Zone 3 area. Therefore, we shall permit CATCO to continue to collect an additional 1.5 cents per Mcf with respect to Zone 3 production to reimburse it in part for the Louisiana state severance tax amounting to 2.3 cents per Mcf if that should prove to be applicable. However, CATCO will be required to continue to hold the 1.5 cents per Mcf in suspense, subject to refund if it should be adjudicated that the lands in Zone 3 lie within Federal jurisdiction.

In its opinion the Supreme Court referred to certain other matters that should be considered in connection with an initial price. The Court was concerned whether a proposed price might result in "a triggering of general price rises or an increase in the applicants' existing rates by reason of 'favored nation' clauses or otherwise." The record shows that the provisions of CATCO's contracts would not trigger the existing favored nation clauses in Tennessee's other contracts because the Cameron area is outside of Tennessee's supply area. Furthermore, the record indicates that no contracts other than Tennessee's would be triggered.

The Court was also concerned that the CATCO price was higher than the price Tennessee had paid elsewhere and some 70 percent higher than the weighted average cost of gas to Tennessee (for 1957). We have concluded on the record that the Court's concern was justified, and that a reasonable initial price should not exceed 18½ cents.

The Court found no support in the record that the public served through the Tennessee system was greatly in need of increased supplies of natural gas. We agree with CATCO that this question has become moot. We have already relied on the CATCO reserves in granting a certificate for a large expansion by Tennessee,[20] and the record in this case shows large increases in Tennessee's needs for gas since 1956.

Apart from the rate aspects we are of the opinion that proof of reserves in this case are sufficient. While CATCO contends that proof of reserves should not be considered part of the essential showing by a producer, we think that proof of reserves in producer certificate cases should ordinarily be made to enable us to consider the ability of the producer to deliver gas, as well as the cost of the gas in the absence of applicable area prices. Here, however, the August 1956 contract between Continental and Tennessee did not require deliveries of so much per day or year, but rather 1,000 Mcf per day for each 8,000,000 Mcf of recoverable gas originally in place in the dedicated reserves. The record indicates that such a contract provision can be met substantially and that deliveries of gas will continue during the term of the contract expiring in 1977.

Refunds

The examiner required CATCO to refund with interest at 6 percent the difference between the sums received from Tennessee and the sums that would have been received under the examiner's 19.92-cent rate. The refund period would extend from the date of initial delivery until the effective date of his order.

CATCO excepts to this requirements saying that from the commencement of deliveries on July 12, 1958, until November 16, 1959, when the mandate of the Court of Appeals for the Third Circuit was issued there was no refund requirement and there is no power available to the Commission under which refunds could be lawfully prescribed. While a refund requirement was inserted in the temporary authorization issued November 17, 1959, CATCO argues,

[20] *American Louisiana Pipe Line Co. et al.*, 21 FPC 70, 75.

this requirement was invalidated by *Sunray Mid-Continent* v. *F.P.C.*, 270 F. 2d 404 (CA10, 1959). Further, CATCO contends, Atlantic was given an unconditional temporary authorization in Docket No. G–15374 that was improperly rescinded on November 17, 1959, when temporary authorization with conditions was issued in Docket No. G–11034.

In our opinion the examiner acted properly in ordering refunds, although we have no power to order reparations. Here we granted CATCO a certificate and approved the proposed 21.4 cent rate. That certificate was subject to challenge when issued and was challenged successfully. The proceedings were remanded by the Supreme Court, and our order of June 24, 1957 was "vacated" by the mandate of the Court of Appeals. We now find that the rate should have been 18½ cents. If CATCO were permitted to retain what it has collected under the 21.4 cent rate and file the 18½ cent rate prospectively only, CATCO would be permitted to retain the portion of the rate found unlawful, the Supreme Court's decision and the subsequent hearing would be rendered in part futile, and CATCO would be unjustly enriched because of procedural delays. As has been said the "right to recover what one has lost by the enforcement of a judgment subsequently reversed is well established." *B. & O.R. Co.* v. *United States*, 279 U.S. 781, 786; compare *United States* v. *Morgan*, 307 U.S. 183, 197. To require restitution of the difference between the two rates, in our opinion, is a reasonable condition of issuing permanent certificates to the CATCO companies under the provisions of Section 7(e) of the Natural Gas Act. In a somewhat analagous situation we required the payment of interest on amounts refunded under a settlement order although no provision for interest had been made in the settlement agreement. *Mississippi River Fuel Corporation* v. *F.P.C.*, 281 F. 2d 919, 927 (CADC), certiorari denied 365 U.S. 827. When ordering a refund under a temporary certificate with a refund provision, the Commission was held authorized to order the payment of interest to avoid unjust enrichment. *Texaco, Inc.* v *F.P.C.*, 290 F. 2d 149 (CA5).

With respect to the period since November 17, 1959, when the Commission's temporary certificates become effective, a refund is appropriate in any case because the temporary certificates in letter form were issued "upon the condition that the rates charged shall be subject to such conditions as the Commission shall lawfully prescribe in issuing a permanent certificate in Docket No. G–11024, including any provision for refund thereby imposed." Such a broad condition is lawful. *Pure Oil Co.* v. *F.P.C.*, 292 F. 2d 350, 353–354 (CA7). CATCO had already begun service, so that it did not have the choice whether to accept or reject the temporary certificate contemplated in *Sunray Mid-Continent* v. *F.P.C.*, 270 F. 2d 404 (CA10) where the Court held that the applicant must not be offered a certificate which leaves entirely open for a future proceeding the question of an initial rate.

With respect to the unconditioned temporary certificate issued to Atlantic in Docket No. G–15374, the refund provision is likewise applicable. The temporary certificate gave no unalterable right to the proposed price. Under Section 7(c) the Commission may issue a temporary certificate in case of emergency pending the determination of an application for a certificate. This appears to contemplate a continuous course of adjustment until the time that a final order determines the conditions under which a permanent certificate shall be issued.

The Commission finds:

(1) Continental, Atlantic, Cities, and Tidewater (CATCO) independent producers of natural gas are engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of

the Commission, and each is, therefore, a "natural-gas company" within the meaning of the Natural Gas Act.

(2) The sales of natural gas hereinbefore described, as more fully described in the applications, are made in interstate commerce, subject to the jurisdiction of the Commission, and such sales by CATCO, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) CATCO is able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act, and the requirements, rules and regulations of the Commission thereunder.

(4) The sales of natural gas by CATCO, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity, and certificates therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in the administration of the Natural Gas Act that the initial price charged by CATCO for sales of gas from its offshore reserves be 18.5 cents per Mcf at 15.025 psia subject to downward Btu adjustment provided in the contract insofar as the Btu content falls below 1000 Btu per cubic foot during any month, except that CATCO may continue to collect an additional 1.5 cents for gas produced in Zone 3 subject to refund with interest to Tennessee if it is finally adjudicated that Zone 3 is subject to Federal jurisdiction.

The Commission orders:

(A) Permanent certificates of public convenience and necessity are hereby issued to Atlantic, Continental, Cities, and Tidewater, authorizing the service and sale, proposed by:

(a) Atlantic in its contract with Tennessee dated August 10, 1956, and filed as Atlantic's FPC Gas Rate Schedule No. 185, as amended;

(b) Continental in its contract with Tennessee dated August 17, 1956, and filed as Continental's FPC Gas Rate Schedule No. 154, as amended;

(c) Cities in its contract with Tennessee dated August 14, 1956, and filed as Cities' FPC Gas Rate Schedule No. 6, as amended;

(d) Tidewater in its contract with Tennessee dated August 14, 1956, and filed as Tidewater's FPC Gas Rate Schedule No. 72, as amended;

and, in each instance the operations and construction reasonably necessary thereto.

(B) Each certificate issued severally to the CATCO companies as provided in Paragraph (A), above, is hereby conditioned so that the base price effective under each of the aforesaid contracts, from the date of initial service thereunder, shall be, until lawfully changed in the manner provided by the Natural Gas Act, 18.5 cents per Mcf at 15.025 psia subject to the downward Btu adjustment provided in the contract insofar as the Btu content falls below 1000 Btu per cubic foot during any month except that CATCO may continue to collect an additional 1.5 cents per Mcf for gas produced in Zone 3 subject to refund to Tennessee with interest at 6 percent if it is finally adjudicated that Zone 3 is subject to Federal jurisdiction.

(C) Each of the CATCO companies shall, within 60 days of the date upon which this order shall become effective, refund to Tennessee with 6 percent interest a sum equal to the difference in the price charged to and collected from Tennessee and the base price set forth in (B) above, applied to all volumes delivered to Tennessee under the contracts which form the subject matter of this

proceeding (Paragraph (A), above) from the date of initial delivery to Tennessee until the effective date of this order.

(D) Within 10 days of the date of refund provided in Paragraph (C), above, each of CATCO companies shall file with the Commission an officially certified statement showing the amount of the refund, its manner of computation, and the interest payments related thereto, and a statement from Tennessee acknowledging the receipt.

(E) The certificates issued to CATCO are not transferable and shall be effective only so long as they continue the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act, and the applicable rules, regulations, and orders of the Commission.

(F) The grant of the certificates to CATCO herein is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the CATCO companies.

APPENDIX 1

Continental Oil Company

Cost of service—Cameron area

Description	Total Col. 7+ Col. 8	Gas only	Condensate and gas			Total	
			Total Col. 5+ Col. 6	Condensate liquids	Gas	Condensate liquids	Gas
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Operating expense:							
Lease expense	263,957	46,013	217,944	26,655	191,289	26,655	237,302
Indirect expense:							
Retirement and abandonments	125	19	106	13	93	13	112
Depletion:							
Leasehold depletion	5,574	114	5,460	668	4,792	668	4,906
Depreciation:							
Lease and well equipment	101,573	18,436	83,137	10,168	72,969	10,168	[1] 91,405
Amortization:							
Intangible drilling costs	162,027					16,737	[1] 145,290
						10.33%	89.67%
Overhead:							
Production department	50,023						
General company	77,155						
Total overhead	127,178	22,170	105,008	12,842	92,166	12,842	114,336
Subtotal	660,434	86,752	411,655	50,346	361,309	67,083	593,351
			100.00%	12.23%	87.77%		
Special facilities expense (Depreciation and Amortization I.D.C.)	7,691					794	[2] 6,897
Subtotal	668,125	86,752	411,655	50,346	361,309	67,877	600,248
Production taxes	46,952					15,736	31,216
Regulatory expense	24,777						24,777
Less:							
T.G.T. Liquids transportation service—credit	(17,117)						(17,117)
Return on rate base at 11 percent	714,333					73,566	640,767
Total production cost	1,437,070					157,179	1,279,891
Volumes							10,014,362
Unit cost							12.78
Exploration cost per Mcf							4.68
Total cost per Mcf							17.46¢

[1] Depreciation and amortization of special facilities adjusted per Examiner's Opinion, page 79.
[2] Allocation of special facilities to gas: $7,691×89.67=$6,897.

APPENDIX 2

CONTINENTAL OIL COMPANY

Rate base and return at 11 percent—Cameron area

Description	Total Col. 7+ Col. 8	Gas only	Total Col. 5+ Col. 6	Condensate liquids	Gas	Total	
						Condensate liquids	Gas
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Lease and well equipment	1,164,600	211,385	953,215	116,578	836,637	116,578	1,048,022
Intangible drilling costs	4,576,989					472,803	4,104,186
						10.33%	89.67%
Producing leaseholds	137,614	2,821	134,793	16,485	118,308	16,485	121,129
Total direct	5,879,203	214,206	1,088,008	133,063	954,945	605,866	5,273,337
Drill tools	110,547					11,420	99,127
						10.33%	89.67%
General investment:							
Production department	60,090						
General company	63,686						
Total general	123,776	20,522	103,254	12,628	90,626	12,628	111,148
Subtotal	6,113,526	234,728	1,191,262	145,691	1,045,571	629,914	5,483,612
			100.000%	12.23%	87.77%		
Special facilities	88,215					9,112	[1] 79,103
Total net investment	6,201,741	234,728	1,191,262	145,691	1,045,571	639,026	5,562,715
Working capital	292,198					29,763	262,435
Total rate base	6,493,939					668,789	5,825,150
Return on rate base at 11 percent	714,333					73,566	640,767

[1] Allocation of special facilities to gas: $88,215×89.67%=$79,103.

APPENDIX 3

CONTINENTAL OIL COMPANY

Computation of amortization of intangible drilling costs using examiner's recoverable reserve estimates, area basis years 1958 and 1959

Year	Gross investment				Reserve for amortization				Net investment Jan. 1	Net investment Dec. 31	Amortization data		
	Balance Jan. 1	Additions	Deductions	Balance Dec. 31	Balance Jan. 1	Additions (revision for amortization)	Deductions (write-offs)	Balance Dec. 31			Gas volume—Mmcf: Jan. 1, depletable	Gas volume—Mmcf: Annual production	Amortization rate
(1)	(2)	(3)	(4)	(5)	(6)	(7) Col. 10 × Col. 14	(8)	(9)	(10)	(11)	(12)	(13)	(14) Col. 13 ÷ Col. 12
1958	4,801,143		255,839	4,545,304		62,127	255,839	(193,712)	4,801,143	4,739,016	[1] 1,305,315	[2] 16,896	1.294%
1959	4,545,304		262,119	4,283,185	(193,712)	162,027	262,119	(293,804)	4,739,016	4,576,989	[1] 1,288,419	[2] 44,056	3.419%

[1] Determination of January 1 reserves: (14.73 psia)

	Mmcf
Examiner's recoverable reserves, 1/1/60	1,244,363
Production estimate	44,056
Reserve estimate, 1/1/59	1,288,419
Production estimate, 1958	16,896
Examiner's initial recoverable reserves (14.73 psia)	1,305,315

[2] Production allocated between 1959 and 1958 on basis of Continental net interest production:

	Continental net interest (14.65 psia)	Percent	Allocated production (14.73 psia)
	Mcf		*Mmcf*
Year 1958	3,832,695	27.72	16,896
Year 1959	9,996,224	72.28	44,056
Total	13,828,919	100.00	60,952

APPENDIX 4

While the condensates may not be in vapor form, movement of such liquids through the pipeline constitutes an engineering problem out of proportion to mere volumes. The factor of 4 was employed in order to recognize the cost relationships between the transportation cost of the gas and the condensates. The computations employed the cost figure of $2,365,584 for the period June 30, 1959–June 30, 1960 from the staff's exhibit as follows:

78,058 barrels (Continental's 1959 liquids) × 1.2 (vapor volume factor) = 93,670 Mcf;
93,670 × 4 (relative cost factor) = 374,680 Mcf.

Mcf gas (1959)	10,014,362	96.394%
Mcf liquids (1959)	374,680	3.606

$2,365,584 (transportation costs June 30, 1959—June 30, 1960) × 3.606% = $85,302;

$$\$85,302 \times \frac{47,169,830 \text{ (CATCO volumes)}}{4 \text{ (companies)}} \times \frac{1}{[1]\ 58,769,006} = \$17,117.$$

[1] CATCO and Shell volumes June 30, 1959—June 30, 1960.

The disparity between the periods covered by these figures and between total volumes and Continental's net working interest volumes requires that the result be considered an estimate only. Furthermore, it is assumed that Shell's gas is being handled in the same way as the CATCO gas.

DECISION

FURTHER PROCEEDINGS ON REMAND UPON APPLICATIONS FOR SECTION 7(C), NATURAL GAS ACT, CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND UPON RELATED SUBSEQUENT APPLICATIONS FILED UNDER THE SAME SECTION OF THE ACT

(Issued August 14, 1961)

SIMPSON, *Presiding Examiner:* This proceeding involves a remand on instructions issued by the Supreme Court of the United States and the reconsideration, as required thereby, of the several applications filed in September 1956, by Continental Oil Company (Continental), The Atlantic Refining Company (Atlantic), Cities Service Production Company (Cities), and Tidewater Oil Company (Tidewater),[1] respectively, each for a certificate of public convenience and necessity pursuant to Section 7(c) of the Natural Gas Act (Act), to authorize the sale to Tennessee Gas Transmission Company (Tennessee) of natural gas produced by or for them from certain joint leases lying offshore Louisiana.

Each of the aforesaid original applications propose the interstate sale of natural gas pursuant to the terms of a separate contract between each Applicant and Tennessee originally committing the producer's 25% share or interest in production from certain specified or limited reservoirs under some 5 joint leases in the West Cameron, 12 such leases in the East Cameron, and 7 such leases in the Ver-

[1] Hereinafter collectively "Applicants" or "CATC companies". Continental filed on September 5, 1956 (G–11024); Atlantic on September 7, 1956 (G–11034); and Cities and Tidewater on September 10, 1956 (G–11046, G–11049), respectively.

million areas of the Gulf of Mexico, respectively, offshore Cameron and Vermillion parishes, Louisiana.[2]

After hearings on the original applications on February 28 and March 1, 1957, the Presiding Examiner filed his initial decision wherein, subject to a condition pertaining to a related application for a certificate filed by Tennessee in Docket No. G–11107, there would have been issued permanent certificates to each Applicant, which for reasons stated in the initial decision would not have been conditioned as to the initial price proposed of 21.4¢ per Mcf (15.025 psia) plus the Louisiana tax of 1¢ per Mcf then in effect.

Summarizing further, the Commission thereafter issued three successive orders—the first on April 22, 1957 (17 FPC 574) granting temporary certificates because of the Commission's view that the evidence of record lacked justification for the price proposed,[3] the second on May 20, 1957 (17 FPC 732) modifying the first to provide for the granting of permanent certificates subject to certain conditions which served to limit the initial price (with tax) to 18¢ per Mcf;[4] and the third on June 24, 1957 (17 FPC 880) after oral argument on rehearing, modifying the second to remove the price condition in order to meet an indication by Applicants of the alternative loss of the gas to Tennessee and its interstate markets.[5]

As the consequence of review initiated in the Court of Appeals by certain petitioner public utility interveners and the New York Public Service Commission the order of the Commission was vacated on jurisdictional grounds (*Public Service Commission of New York* v. *Federal Power Commission*, 257 F. 2d 717, 723 (C.A. 3d, 1958)), a result affirmed by the Supreme Court of the United States on certiorari, but with instructions to remand for further proceedings in accord with its opinion and judgment delivered June 22, 1959, which placed particular emphasis upon the issue of public convenience and necessity as related to the price proposed.[6]

In June 1958, three of the CATC companies had each filed a further separate application seeking additional authorization to sell and deliver to Tennessee natural gas produced from East Cameron Block 63 in accordance with a dedication contained in a certain separate proposal which the latter had accepted that same month. Subsequently Tidewater similarly filed,[7] and by order issued

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[2] The contract date and the producer's FPC gas rate schedule designation: Continental-Tennessee contract, August 17, 1956, Rate Schedule No. 154; Atlantic-Tennessee contract, August 10, 1956, Rate Schedule No. 185; Cities-Tennessee contract, August 14, 1956, Rate Schedule No. 6; and Tidewater-Tennessee contract, August 14, 1956, Rate Schedule No. 72. On various dates in 1957, 1958 and 1959, each Applicant released its interest in certain leases in 6 blocks in the East Cameron Area and in an equal number of blocks or parts of blocks in the Vermillion Area and assigned or farmed-out a lease in Block No. 86 in the latter area—involving in all interests in some 56,250 acres of the 95,250 acres originally dedicated. Immediately prior to the commencement of the reopened proceedings each Applicant filed an amendment deleting such leases from its application as originally filed. One of the Applicants (Atlantic) has also filed an appropriate supplement to its rate schedule.

[3] Substantially on the grounds that the price proposed (21.4 cents per Mcf, plus tax) was higher than Tennessee was paying under any other contract and that the record contained insufficient evidence on which to base a finding that public convenience and necessity required the sale at the rate level proposed.

[4] The highest price then paid by Tennessee for the purchase of any gas produced in the Southwest area.

[5] Three of the CATC companies were already involved in rate proceedings before the Commission which had been initiated under Section 5(a) of the Act. The latter order advised that the Commission was concurrently instituting a similar rate investigation with respect to the remaining CATC company—Cities, Docket No. G–12780.

[6] The vacation and remand was issued by mandates of the Court of Appeals November 16, 1959. Each Applicant received from the Commission a temporary conditional authorization effective with the issuance of the mandate.

[7] February 29, 1960; based on a corresponding letter agreement of July 1958.

February 16, 1959, in Docket No. G–15330, the Commission granted a certificate to Cities, conditioned as to price,[8] the remaining applications being considered, respectively, as a pending amendment to the original application of the Applicant.

Following the issuance of the mandates by the Court of Appeals, November 16, 1959, the Secretary of the Commission issued his "Notice of Hearing, and Consolidation" dated December 11, 1959, reopening the original proceedings, consolidating that in Docket No. G–15330, and setting the matters involved and the issues presented by the aforesaid original applications, the pending amendments, and the consolidated docket for hearing commencing January 12, 1960. However, upon motion by Applicants for a postponement of the hearing and for a prehearing conference, the Secretary, by notice dated December 30, 1959, entitled "Notice Vacating Hearing and Fixing Prehearing Conference", vacated his previous notice of hearing and directed a prehearing conference be held commencing January 11, 1960, before the designated Presiding Examiner, for the purpose, in part, of fixing a date of hearing within the limits of a date specified by him. The prehearing conference so arranged was held in the manner provided, the Presiding Examiner thereafter filed his "Ruling Specifying Results of Prehearing Conference and Fixing Date of Hearing", dated January 12, 1960, which, among other matters, directed that Applicants prepare and serve the expert testimony to be offered on their behalf not later than, and that the hearing convene on March 15, 1960, for the purpose of receiving, as provided, Applicants' entire cases-in-chief, and for the further purpose of setting a date for the commencement of cross-examination with respect thereto.

In accordance with the foregoing notices and prehearing ruling, these remanded, reopened, and consolidated proceedings came on for hearing, commencing March 15, 1960, and concluding January 19, 1961.[9] Six interveners entered an appearance in the reopened proceedings, of which four took an active part in the presentation of evidence and the cross-examination of witnesses.[10] Simultaneous initial and reply briefs have been filed on behalf of all active participants, including the Applicants, the four interveners, and the Commission's Staff.[11] A final brief has been filed by the Applicants.

By order issued February 24, 1961, the Commission denied a motion made on behalf of Applicants at the conclusion of the hearing on January 19, 1961, to omit the intermediate decision procedure.

The Issues

In the original proceedings the basic issues were those prescribed by the provisions of Section 7(c) and Section 7(e) of the Act—the former section relating to the Commission's jurisdiction over the person and the proposed action, and the latter section relating principally to the qualifications and ability of the

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[8] *Viz.*, the initial price shall agree with that in Docket No. G–11046 herein and any change which finally results from these proceedings.

[9] There were, in all 48 days of hearing sessions. The record thereof consists of 7,482 pages of additional transcript, 45 additional exhibits, and 27 additional items by reference. Applicants presented 18 witnesses in chief and 3 in rebuttal; three gas distributor interveners presented jointly 7 witnesses; intervener Tennessee 3 witnesses; and Staff 3 witnesses. This compares with 327 pages of transcript, 6 exhibits, 4 items by reference, and 3 witnesses of the remanded earlier proceedings of February 28 and March 1, 1957.

[10] In these reopened proceedings the active interveners are: The Brooklyn Union Gas Company, Long Island Lighting Company, Public Service Electric and Gas Company, (N.J.), and Tennessee Gas Transmission Company. While the New York Public Service Commission, reentered its appearance, and Consolidated Edison Company of New York, Inc., and the Pennsylvania Public Service Utility Commission, respectively, entered initial appearances, none of these latter actively participated in the introduction of evidence.

[11] The New York Commission filed a statement in lieu of initial brief in which it concurred in the joint initial brief of the three gas distributor interveners.

Applicant to perform, as well as to the issue of public convenience and necessity.

In these immediate proceedings no issues remain with respect to the Applicants' status as a "natural-gas-company" (Sections 7(c) and 2(6)) or the jurisdictional character of the existing and proposed deliveries and sale of Cameron area gas to Tennessee, or as to whether any one of the Applicants is "qualified" or is "able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Act and the requirements, rules, and regulations of the Commission thereunder" (Section 7(e)).

The primary issues in these remanded proceedings lie under Section 7(e) and, in effect, are: (1) whether the proposed service, sale, operation, construction—is or will be required by the present or future public convenience and necessity without condition as to the proposed price of 21.4¢ per Mcf (before tax), and, (2) if a condition be required as to price, what that condition should be.[12]

THE CONTENTIONS

In substance, Applicants contend that public convenience and necessity require certificating the CATC sales at 21.4¢ per Mcf; intervener gas distributors contend that the in-line price for the CATC gas is 17¢ per Mcf exclusive of tax reimbursements; and Staff contends that the CATC gas unit cost of service is 17.33¢ per Mcf, that the certificates should be conditioned at a price of 16.4¢ per Mcf (15.025 psia),[13] and that Applicants should be required to refund amounts collected to date attributable to charges made for CATC gas in excess of said rate of 16.4¢.

In support of their contention Applicants assert, in brief, that the CATC 21.4¢ price is in line with prices paid in South Louisiana by interstate pipeline companies during the period 1952–1955 for deliveries of gas to begin as early as November 1953, as well as with the current onshore prices paid under earlier contracts; and that the proposed price is in line with comparable prices as of the time of the Commission's decision herein (June 1957), as well as with prices current.

Applicants additionally assert, in brief, that the reserves dedicated to Tennessee are needed to replace reserves being used to meet the constantly rising demands of Tennessee's customers; and that the reserves are convenient to Tennessee's system, are one of the largest reserves available to the domestic market, and provide Tennessee with access to an area of substantial potential additional uncommitted reserves.

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[12] Briefly, in its remand opinion the Supreme Court held that the evidence of record was insufficient to support a finding of public convenience and necessity prerequisite to the issuance of permanent certificates, instancing, in effect, that the proposed price (a) was higher than any price paid by Tennessee, including that paid for offshore purchases in the West Delta area of Louisiana; (b) was some 70 percent higher than the weighted average cost of gas to Tennessee; and (c) was greatly in excess of prices paid by Tennessee for gas from leases in southern Louisiana. It also remarked that Tennessee's undertaking to construct the pipeline to the producers' offshore wells was unsupported by evidence of practice or custom in that respect; that there was no data to support treating Tennessee's free transportation of producers' distillates ashore as *de minimis;* that evidence that increases would not be triggered under existing "favored nation" clauses was not convincing; and that there was no support for finding that Tennessee's system was sufficiently in need of increased supplies of natural gas in the premises. The court further held that rates are not the only factor bearing on public convenience and necessity, that a "just and reasonable" rate hearing was not a prerequisite to the issuance of a producer certificate, but that recent price trends made price a matter of prime importance in such cases.

[13] No explanation is given for recommending a 16.4 cent price.

Applicants also assert, in brief that trends in demand, supply, costs, revenues, and price support the proposed price (21.4¢).

Applicants further assert, in brief, that Tennessee's construction of the offshore CATC pipeline and gathering facilities is based upon a general industry practice to receive the gas in the field where produced; that the contract provision for the transportation by Tennessee of CATC distillate and liquifiable hydrocarbons without charges confers upon Tennessee operating advantages of a substantial nature and in any event would impose upon the latter but *de minimis* costs.

Applicants finally assert that the proposed price has not triggered the favored nation clause in any purchase contract.

Tennessee asserts, in brief, that at the time of the negotiation of the CATC contracts other sales were being made in the southern Louisiana area at total prices ranging from 20¢ to 21.4¢ per Mcf; that with an originally assumed purchase of 87,600,000 Mcf of CATC gas for an entire year (240,000 Mcf per day) the weighted average cost of gas to it for 1958 would have been increased by but 0.97¢; and, that the actual increase in Tennessee's weighted average purchase costs for 1959 attributable to a full year's purchase of CATC gas was less than 0.44¢ per Mcf.[14]

Tennessee also asserts, in brief, that it has an urgent need for the additional supply of natural gas; that the CATC gas reserves are readily accessible to its system; that these reserves have a suitable deliverability and their acquisition is particularly beneficial to it; and that its construction of facilities affords ready access to additional potential reserves in the area.

Tennessee further asserts, in brief, that with respect to larger reserves of natural gas it is common practice for pipelines to take the gas in the field and to construct the necessary facilities to do so; that its transportation of distillate and liquifiable hydrocarbons for the CATC Applicants in the gas stream from the platform to a shore separation facility affords an advantage to Tennessee in contributing to the disposal of these products in a manner which assures a steady rate of delivery of the gas; that no cost for this movement is incurred so long as Tennessee has unused capacity in its CATC facilities and that even if the gas carrying capacity of these facilities are reduced by the volume of these products carried the cost of transportation would be equivalent to but 0.015¢ per Mcf of gas transported.

Tennessee finally asserts that the CATC contracts do not affect or trigger the price in any other gas purchase contract of itself or any other purchaser.

The intervener gas distributors assert in support of their contentions, in brief, that the benchmark is the 1957 price level in the southern Louisiana producing area; that the evidence in these proceedings falls short of establishing that Tennessee's need for the CATC gas is of such urgency as to justify issuance of unconditioned certificates; that the capital cost per Mcf of gas reserves discovered in the Cameron area is in line with average company experience, that Applicants' conclusions with respect to the trends of productivity and drilling costs per Mcf of new reserves found are unwarranted; and, that the infirmities shown in major items render Continental's cost of service evidence unacceptable as a justification for a price higher than Interveners' contended-for in-line price of 17¢.

Staff asserts, in brief, that utilizing book figures of the operator, Continental, for the test year 1959, making proper adjustments thereto for out-of-period

[14] Approximately 10,000,000 Mcf of CATC gas as compared with Tennessee's 1959 actual requirements of 721,076,409 Mcf—15,025 psia. The former figure represents an average of 27,397 Mcf per day.

or non-recurring costs, and applying accepted methods of allocation, a unit cost of service of 17.33¢ per Mcf is obtained for the CATC Applicants' Cameron area gas.

Further contentions of the participants are as set forth in following sections of this decision which dispose of the specific matter in controversy.

The Evidence and Findings

Tennessee's Gas Requirements

Tennessee's system traverses 16 states from Texas to New England and serves some 100 customers, among them distributing companies supplying natural gas in many large cities and industrial areas east of the Mississippi River. Some 70% of Tennessee's customers are requirements type of customers, solely dependent upon Tennessee for their supplies of natural gas.

While as of August 1956, when the CATC gas purchase contracts were executed, Tennessee's system peak day deliverability was 2,361,000 Mcf as of 1959 Tennessee's authorized peak day deliverability amounted significantly to 3,083,000 Mcf. Correspondingly, 1956 actual annual requirements of 635,152,000 Mcf increased, to an actual total of 666,139,000 Mcf in 1957, and again to 735,518,000 Mcf in 1959 (14.73 psia).[15]

In 1958, Tennessee's life index, including Cameron area reserves, stood at 17.3 years,[16] but it is to be noted that in the matter of the application filed by Tennessee in 1958 to serve gas to the Chicago-Gary area of northern Illinois and northern Indiana (Docket No. G–16842), it appeared that Tennessee could assure a deliverability for full system requirements from slim and depleting reserves for only 11 years and that the Commission in its opinion issued May 12, 1959, there held, in effect, that in the matter of future expansion applications Tennessee would first have to demonstrate its ability to supply all existing and proposed requirements for a period of at least 12 years (Opinion No. 320, 21 FPC 653 at 657 and 664).

It is also to be observed that Tennessee has been filing substantial applications year by year to meet the increased requirements of its customers and that

[15] Including sales, net storage, and used, lost and unaccounted for gas. While these figures represent a 1956–1959 increase in annual requirements of 15.8% they fail to give full effect to two large deliveries which did not commence until the fall of 1959. Increases in peak day deliverability, including latterly, Midwestern Gas Transmission Company, are generally reflected in the following table, thus:

Docket and filing date	Peak day deliverability (Mcf)	Status
At August 1956	2,361,000	Authorized.
G–11107 (1956)	2,719,000	Authorized.
G–16842 (1958)	3,083,000	Authorized.
CP60–94 (1960)	3,234,000	Application.

[16] However, in this proceeding Tennessee has reduced its estimate of Cameron offshore original recoverable, reserves from an initial 1.68 trillion cubic feet to some 1.323 trillion cubic feet (14.73 psia). Applicants have also currently revised their original estimates downward to 0.7 trillion cubic feet (14.73 psia) which would have provided a life index contribution of about one year.

based upon customers' estimates Tennessee is confronted with the probability of having to continue to meet such increases in requirements in the future.[17]

There is no doubt but that in 1956 Tennessee required, and also now requires, the Cameron gas volume as a part of a supply which it had to have and has to have to maintain deliveries from depleting reserves and to meet the continually increasing demands of its customers.

CATC-Cameron Natural Gas Reserves

Current estimates of initial reserves in place dedicated to the Tennessee contract are (14.73 psia) :[18]

Field Block	Applicants' (Exh. 21) (Mmcf)	Tennessee's (Exh. 40) (Mmcf)
62	89,038	95,843
64	44,750	141,810
71	178,085	220,811
192	560,083	1,122,361
Total	871,956	1,580,825

The estimate of such reserves for the Blocks 49 (abandoned) 62, 71 and 192 fields, testified to by the same Tennessee witness and received in the original hearing (1957) as a part of Applicants' case-in-chief, totalled the considerably larger amount of 1,995,659 Mmcf (14.73 psia).[19]

The evidence pertaining to witnesses' qualifications, and to the volumetric methods of estimating reserves used by each, affords an insufficient basis upon which to select between reserve estimates on the basis of the relative competency of the two witnesses or on the basis of the method used. However, previous estimates of reserves, in effect presented on behalf of both Applicants and Tennessee in the original hearing, serve to cast upon Applicants a particular burden of proof or persuasion which, as a matter of law, is in no-wise altered either by the fact that Applicants' witness for the first time presents his own

[17] The increases in estimated annual requirements, including those of its affiliate Midwestern Gas Transmission Company have been in part as follows :

For	Estimated requirements	
	G–9454, 1956 (Mcf)	CP60–94, 1960 (Mcf)
1962	856,526,000	948,624,000.
1963	864,289,000	945,583,000 (sic).
1964	864,333,000	949,704,000.

[18] Unless otherwise stated all reserve volumes are on a 14.73 psia pressure basis.

[19] The exclusion of the overestimate of original gas in place in the Block 49 field (38,141 Mmcf) reduces the 1,995,659 Mmcf to 1,957,518 Mmcf. The application of 80% and 85% recovery factors to the 1,995,659 produces the then estimated recoverable reserves of 1,673,926 Mmcf.

estimate of such reserves or by the mere fact that Applicants have conducted additional drilling since the earlier estimates.[20]

Omitting reference to the depleted and abandoned Block 49, and also excluding at this stage reserve estimates presented for the first time with respect to Block 64, Applicants' N, P and Q sands of Block 71, and the C, D, I, No–1, and S sands of Block 192,[21] there results the following direct comparison between the current estimates of original reserves in place and those previously testified to in 1957 with respect to Exh. 2 (14.73 psia):

Field Block	Joint Exh. 2 (Mmcf)	Applicants' Exh. 21 (Mmcf)	Tennessee's Exh. 40 (Mmcf)
62	232,776	89,038	95,843
71	288,840	127,154	171,311
192	1,435,903	538,757	1,059,968
Total	1,957,519	754 949	1,327,122
Percent of Exh. 2	100.0	38 6	67.8

The volumetric method as used by both witnesses requires a determination of the reservoir void space (cubic feet per acre-foot) as a step in estimating gas in place,[22] and a determination of average reservoir pressure at datum level,[23] reservoir temperature,[24] and a compressibility factor related to gravity and reservoir pressure,[25] all to obtain gas in place per acre foot. Upon the further determination of area and sand thickness to get reservoir volume in acre feet and ultimately total gas in place, the subsequent application of a recovery factor yields the estimated recoverable gas.[26]

Thus the eight factors having a prime bearing upon the volumetric method's result include productive area, sand thickness, porosity, connate water percent, average reservoir pressure, reservoir temperature (°F), compressibility, and the recovery factor, and with respect to each, as applied to most of the sands in each of the fields, there are generally substantial differences between the two witnesses, and between each of them and Exh. 2.

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[20] Exh. 2 sub-surface data rests principally upon the drilling of 10 CATC producing wells and 2 dry holes, Exh. 40 data upon the drilling of a cumulative total of apparently 23 CATC producing wells and 5 dry holes, by fields as follows:

Field Block	Exhibit 2 producers	Dry holes	Exhibit 40 producers	Dry holes
49	1	1		
62	1		2	1
64			2	1
71	2		5	1
192	6	1	14	2
Total	10	2	23	5

[21] The witnesses only infrequently correlate their differently designated but corresponding sands. However, depths, reservoir pressures, adjusted production data, and completions, laboriously paralleled, appear to yield reasonably safe correlations.

[22] Involving the application of a porosity percent and connate water factor to a gross void of 43,560 acre-feet.

[23] Used in terms of atmospheres, i.e., a multiple of an assumed atmospheric pressure, here 14.73 psia.

[24] Used in terms of a temperature correction factor.

[25] The "Z" factor; used as 1/Z.

[26] Before a small shrinkage due to condensation and fuel losses.

The Original Fields and Sands Block 62 Field

The productive limits of a reservoir represent the gas-water contact, or the location of faults or barriers, or limits established by means of log and core analysis.

The productive area for the sands in the Block 62 field, less the D–4 sand omitted in Exh. 40, is computed in Exh. 2 to total 4,530 acres, compared with 3,109 acres computed in Exh. 21, and 2,159 acres in Exh. 40, the indicated average reductions in the original acreage (Exh. 2) amounting to 31% in the former exhibit and 52% in the latter.

This field has had a dry hole (A–4) drilled since the preparation of estimates in 1957. While from both exhibits it would seem that this fact operates to effect a reduction in the estimated productive limits for the D–3, D–4, F–1, and F–2 sands, it would likewise appear that no such effect results with respect to the F–3 sand. However, other than inconclusive testimony of Tennessee's witness pertaining generally to the removal in Exh. 40 of the seismic fault (Exh. 2) of the F–1 sand, and the extension of the adjacent MCN area in the case of the F–3 sand, the only testimony which throws any light on the reductions is the reference by Tennessee's witness to the additional drilling which, in the witness' summary language, more or less narrowed sand productive limits down to the confines of the drilling unit. Thus, the current conclusions of neither witness as to sand productive limits are so supported by the testimony as to justify the respectively proposed reductions.

All other things being equal the evidence does require here acceptance of those estimates which would have the lesser effect in reducing the estimated productive area upon which Applicants have herein previously stood. Accordingly, Applicants' witness' estimate of 3,424 stated acres of productive area for the Block 62 sands, including the D–4 sand, is accepted.[27]

Sand thickness or the net pay rests principally upon an interpretation of electric and micrologs.

Applicants' witness consistently reduces the estimated sand thicknesses in this field, whereas Tennessee's witness manifests a certain tendency to increase them, explaining elsewhere in his testimony that such increases have been due to changes based on further experience in the interpretation of electric logs in the offshore area. As above stated, since the time of Exh. 2 there has been certain additional drilling, particularly in the MCN–CATC field unit. Data obtained from the resulting wells and dry holes has apparently influenced the sand thickness as well as the productive area results obtained.

Using the above accepted 3,424 acre-feet for the four stated sands and the individual thicknesses assigned them in Exhs. 2, 21, and 40, respectively, a general overall comparision of the sand thickness determinations, in the form of weighted averages, results as follows:

	Exh. 2	Exh. 21	Exh. 40
Average sand thickness (feet)	24 3	13 1	21 9
Relative percent	100 0	53. 9	90. 1

As before stated, in relation to estimates of productive areas, it is here also appropriate to take that qualified or supported estimate which shows the lesser reduction with respect to the previous Exh. 2 individual sand results. It is

[27] Including an estimate of 315 acres for the D–4 sand. The participants treat the difference in reserve estimates for the Block 62 field as not significant. However, larger differences in results, such as those which appear with respect to the Block 192 field, require a general analysis of similar underlying factors in other fields.

noted that in the instance of the D–3 and F–2 sands, however, the witnesses disagree as to the direction of the sand thickness correction, as compared with Exh. 2, Applicants' witness reducing and Tennessee's increasing it.

On the basis of the foregoing and in these prevailing inconclusive circumstances and consistent with the method of selection herein established, it is appropriate to make the following selections of sand thicknesses from the three exhibits: D–3 sand, 8.0 feet; D–4 sand, 3.9 feet; F–1 sand, 21.6 feet; F–2 sand, 16.0 feet; and the F–3 sand, 20.3 feet.

With respect to porosity, all three exhibits use a factor of 30% except that Applicants' witness applies 28% to the F–1 sand and 32% to the F–2 sand which to that extent serves to produce a relative net negative difference of but 321 acre feet (1.6%) a matter of relatively minor proportion. The 30% therefore appears to be an acceptable porosity factor for these sands.

Applicants' witness employs a connate water factor of 25%, as compared with the 20% used in Exh. 21 and retained by Tennessee's expert. No justification appears for a change to the 25% factor.

Average pressures vary only with respect to two sands, but due to differences between the witnesses as to average depths, Applicants' witness is using, in effect, slightly lower pressures with increases in depth. This witness measured reservoir pressures where available but otherwise calculated pressure by applying an established regional gradient to the average depth of the reservoir. Tennessee's witness used average initial pressures based on actual pressure surveys where available or derived a pressure from a gradient curve normal for the general area. Nothing in the evidence indicates what was done in the instance of this (Block 62) field. However, the differences are not critical.

Temperatures differ substantially only with respect to the shallower D–3 sand and, except for the use of an interpolated temperature for the D–4 sand, it is proper to accept those used by Tennessee's witness.[28]

Applicants' witness calculates the compressibility factor from data obtained from gas analyses where available and otherwise from general charts based on the laboratory compressibility of gases of various gravity, whereas Tennessee's witness obtained the deviation factor from prepared curves of an undisclosed nature. The evidence of record fails to impeach the deviation factors originally presented in Exh. 2.

The reserves resulting from the foregoing selection of porosity, connate water, atmospheres, temperature correction and compressibility factors and selections of sand Mcf per acre foot are in general close to those determined by Tennessee's witness but higher than those obtained by Applicants' witness.[29] Reservoir volumes in terms of productive acre feet, while lower than the results in Exh. 2, are generally so much higher than those contained in Exh. 40 and Exh. 21

[28] Only Tennessee's witness provides data concerning the related temperature correction factor.

[29] Gas unit volumes by sands, thus (14.73 psia):

Sand	By selected factors (Mcf/acre-feet)	Exhibit 21 (Mcf/acre-feet)	Exhibit 40 (Mcf/acre-feet)
D–3	1989	1912	2019
D–4	1965	1928	
F–1	2183	1914	2190
F–2	2337	2328	2334
F–3	2328	2228	2323

as not to be entirely comparable.[20] The foregoing considerations indicate, in totality, that the evidence fails to support acceptance of a gas reserve estimate for the Block 62 field less than that testified to by Tennessee's witness. (95,843 Mmcf).[21]

Block 71 Field

Here too the testimony affords no simple basis upon which a selection may be made between the conflicting reserve estimates for the Block 71 field. The combined results do indicate, however, the propriety of a downward revision of the estimates set forth in Exh. 2.

Less the untested G–1 sand omitted in Exh. 40, and not including the later N, P and Q sands, the overall sand productive area for the field is computed in Exh. 2 to total 6,940 acres, compared with 3,979 acres computed in Exh. 21, and 4,533 acres in Exh. 40. The average areal reduction thus amounts to some 43% in Exh. 21 and 35% in Exh. 40. In arriving at their respective estimates both witnesses used the available well information, but Tennessee's witness also consulted geophysical interpretations, which Applicants' witness did not do.[22]

The Block 71 field has had a dry hole (A–5) and 3 wells drilled since the preparation of estimates in 1957 (Exh. 2). The drilling has apparently led both witnesses to reduce productive limits of the various sands, except that in lieu of previous limits Tennessee's witness assigns 640 acres of productive area to the I–4 sand, penetrated by the A–2, –4, and –6 wells and a dry hole, as contrasted with Applicants' witness' enlargement of the corresponding original productive area. Exh. 2 indicates a single well completion in each of the H–1 and I sands, later Exhibits 21 and 40 indicating 3 completions in the H–I sand, 2 in the I sand, and 1 in the I–4 sand. Proceeding according to the premises established in the instance of the Block 62 field, above, Tennessee's witness' estimate of 4,533 acres of productive area for the Block 71–H–I, I, and I–4 sands is accepted, to which is added an area of 431 acres for the so-called H (or G–1) sand as computed by Applicants' witness. While there are no completions in this latter untested sand, Applicants' witness did have core analyses pertaining thereto. Accordingly, a productive area of 4,964 acres is accepted for the four original sands in the field.[23]

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[20] Productive acre-feet, thus:

Sand	By selected factors (acre-feet)	Exhibit 2 (acre-feet)	Exhibit 21 (acre-feet)	Exhibit 40 (acre-feet)
D–3	3,584	9,808	2,395	6,867
D–4	1,229	5,084	1,240	
F–1	23,587	35,848	10,989	11,515
F–2	7,536	9,741	4,706	7,064
F–3	31,073	43,559	22,484	17,334
Total	67,009	104,100	41,814	42,780

[21] In totals (14.73 psia): on the basis of the selected factors—150,984 Mmcf; Exh. 21—89,038 Mmcf; and Exh. 40—95,843 Mmcf. Cf., Exh. 2—232,776 Mmcf.

[22] The witness's direct examination and cross-examination going to the employment of geophysical data as a tool in the instance of multi-layer sands such as characterize these fields is very inconclusive as to the reliability and usefulness of such data.

[23] The total includes the assignment by Tennessee's witness of 640 acres to the I–4 sand in lieu of Applicants' witness' estimate of 1,736 acres and the 1,232 acres of Exh. 2. While this sand appeared in 4 wells, has a completion in one well, and was tested in yet another, the witness testified that a permeability barrier and some water is involved—matters which Applicants' witness does not mention or reflect in his exhibit and which Applicants' did not rebut.

Except for the G–1 sand both witnesses increase the sand thicknesses. Using the foregoing accepted productive area acreage as a weighting factor generally comparable weighted average sand thicknesses for the combined H–1, I and I–4 sands results as follows:

	Exh. 2	Exh. 21	Exh. 40
Average sand thickness (feet)	17.32	18.46	18.63
Relative percent	100.0	106.6	107.6

For the reasons stated previously, in relation to the Block 62 field, and in the absence of a specific justification or support in the testimony for any other determination, it is appropriate here also for testing purposes to take that estimate of thickness which shows the lesser change with respect to the earlier Exh. 2 results upon which both Applicants and Tennessee previously stood. Accordingly, the following thicknesses are accepted, to wit: G–1 sand, 5.8 feet; H–1 sand, 21.3 feet; I sand, 15.2 feet; and the I–4 sand, 8.0 feet.

The Exh. 2 porosity of 30% is reduced in both Exhs. 21 and 40 to 25%, except with respect to the H–1 sand where Applicants' witness uses 27%. Tennessee's witness did not use the inherently unreliable side-wall core analyses as a sole determining factor but relied on higher porosities in the Miocene sand as indicated by electric logs and information pertaining to southern Louisiana and off-shore fields. Applicants' witness considered available core analyses but used the electric logs and employed a judgment based upon his 15–16 years experience and familiarity with area fields. However, there is no specific justification in this evidence for using in the single instance of the H–1 sand a porosity higher than the otherwise generally applied 25%.

Tennessee's witness retains in Exh. 40 the 20% connate water factor previously used in Exh. 2. Applicants' witness uses 20% for the H–1 and I sands, 25% for the G–1 sand, and 30% for the I–4 sand. Because of core contamination by the drilling fluid, Tennessee's witness did not use side-wall core analyses for the determination of the connate water percent, but did use as a guide those certain laboratory results pertaining to Miocene samples taken by other companies in area fields which indicated connate water factors in the order of 12–20%. Applicants' witness considering the available side-wall core analyses, determined connate water percents from the electric log. However, he offers no specific support for the higher percents selected by him. Accordingly, a connate water factor of 20% is acceptable for these sands.

Initial reservoir pressures used by Applicants' witness are higher for the G–1, H–1, and the I–4 sands[34] but lower for the I sand; while those used by Tennessee's witness are lower for the H–1 sand and higher for the I and I–4 sand. The methods used by the witnesses to determine pressures—actual pressures where available or pressures calculated from gradient curves—is explained in connection with the above considerations pertaining to the Block 62 field. None of the testimony attempts to reconcile or explain these several differences. Adopting, again, the rule of least departure from the data contained in Exh. 2, for the reasons and to the extent previously stated, the following pressures are accepted: G–1 sand (untested), 3470 psia, H–1 sand, 3551 psia, I sand, 4118 psia, and the I–4 sand 4459 psia.

Applicants' witness adopts for each sand a reservoir temperature significantly lower than that appearing in Exh. 2, while Tennessee's witness substantially retains the earlier temperatures.

[34] The exceptionally low pressure given the I–4 sand in Exh. 2 cannot be reconciled in any degree with those currently used for that sand by either witness. The differences between the witnesses in pressures does not appear to be directly related to differences in depth.

As before Applicants' witness used available measured reservoir temperatures, otherwise temperatures calculated by the application of an established regional gradient. Tennessee's witness, who made the earlier determinations in Exh. 2, following the same procedure, used where necessary temperatures taken from a curve derived from reservoir measurements taken in southern Louisiana area fields. Neither witness explaining the temperature determination here used by him,[35] the reservoir temperatures appearing in Exh. 2 are retained along with the corresponding temperature factor.

With respect to deviation Applicants' witness has used factors generally higher than those in Exh. 2, while Tennessee's witness, in substance, retains the Exh. 2 factor for the H–1 and I sands but increases the factor for the I–4 sand.[36] No justification exists for changing the factors used in Exh. 2 for the untested G–1 sand or the H–1 and I sands. The factor determined for the I–4 sand by Applicants' witness is accepted.

The reserves in place which result from the foregoing selections of porosity, connate water, atmospheres, temperature correction and compressibility factors, as well as area and sand thickness, as a test indicate that the record supports the acceptance of a gas reserve estimate for the above 4 stated sands of the Block 71 field of the approximate magnitude of that derived by Tennessee's witness. (171, 311 Mcf.) [37]

Block 192 Field

With respect to this field the testimony again affords no sufficient basis upon which to choose directly between the reserve-in-place estimates proposed by the two witnesses.

The Block 192 field had 6 producing wells and 1 dry hole drilled at the time of the 1957 estimates, since which an additional 8 producing wells and 1 dry hole have been drilled. All the original Exh. 2 sands have been at least tested.[38]

[35] Applicants' witness testified offhand to a general gradient of 1.2°–1.4° F. per 100 feet of depth plus a mean surface temperature of 74° and it would appear that this witness has used an average of the foregoing while Tennessee's witness has used the 1.4° F. rate.

[36] The general methods by which the witnesses derived these factors has been previously explained (Block 62 field, *supra*).

[37] The comparative initial reserves are (14.73 psia):

	By selected factors (Mmcf)	Exh. 2 (Mmcf)	Exh. 21 (Mmcf)	Exh. 40 (Mmcf)
Total gas in place	160,649	288,840	127,154	171,311
Less G–1 reserve	4,847	31,081	4,463	
Resulting reserves	155,802	257,759	122,691	171,311
Percent index	60.4	100.0	47.6	66.5

[38] Completions are as follows:

Sand	Exh. 2 (1957)	Exh. 40 (1960)
B–15	1	4
C–1		
D–2	1	2
D–4	1	1
G–2		2
I	1	2
I–2	2	2
J–3	1	1
L–1	1	4
Total	8	18

For structural interpretation Tennessee's witness used log and core information available from all wells drilled in the Block 192 field, including that from certain wells drilled by Shell Oil Company in adjacent Block 82,[39] as well as certain geophysical information Applicants' witness proceeded in the same manner, on the basis of like information obtained from like sources, and in brief, found productive limits through the use of electric logs and core analyses but did not use seismic data.

The estimated productive area for the Exh. 2 sands of this field totalled 24,892 acres in Exh. 2, as compared with a generally corresponding estimate of 10,185 acres in Exh. 21 and 15,095 acres in Exh. 40. The reduction in areas of sands appearing in Exh. 2 thus averages some 60% in Exh. 21 and 40% in Exh. 40.[40]

The resort by each witness to substantially the same underlying data contributes to the impossibility of making a simple selection between the area results obtained by each. However, as in the instance of the preceding fields, it is appropriate to resort to the earlier estimates contained in Exh. 2 as a guide to the determination of whether Applicants have here sufficiently discharged their burden of proof as to the issue of initial reserves in place.

The productive areas determined by Tennessee's witness are less than those in Exh. 2 in six sands.[41] Applicants' witness' sand areas are less than those in Exh. 2 or Exh. 40 in all instances except with respect to the L–1 sand, where the area is greater than in Exh. 2 but less than in Exh. 40.

For the 6 sands the total area found by Tennessee's witness of 9,640 acres is accepted. With respect to the C–1 sand Tennessee's witness' area is but 2.7% greater than that in Exh. 2, while Applicants' witness' area is 46.7% less. With respect to the I sand Tennessee's witness determines an area some 15% larger than in Exh. 2, while Applicants' witness determines an area smaller than in Exh. 2 by approximately 5%. In these circumstances the areas used in Exh. 2 for the C–1 and I sands are not to be considered as impeached. With respect to the L–1 sand, where completions have increased from 1 to 4 since 1957, Applicants' witness increases the area computed in Exh. 2 of 1,357 acres by some 34% while Tennessee's witness increases the area by some 94%. While neither change is specifically supported, for the reasons previously given, the L–1 sand area determined by Applicant's witness of 1,821 acres is accepted.

There is agreement by the witnesses that the previously listed E–1, E–2, and F–2 sands contain no recoverable reserves.[42]

Using the pay thicknesses set forth in each of the three exhibits for the sands here in question and weighting by the respective portions of the 14,022 acres of total productive area, determined as in the second preceding paragraph, average thicknesses result as follows:

	Exh. 2	Exh. 21	Exh. 40
Average sand thickness (feet)	24.6	21.6	25.1
Relative percents	100.0	87.7	102.3

Proceeding as previously herein it is appropriate in the absence of any specific justification for any other determination, to take generally that estimate of sand thickness supported by the testimony of a qualified expert witness which shows the lesser reduction from the Exh. 2 computation, as follows: B–15 sand,

[39] Used in relation to the ER, FL, FQ, FN, IB, IE, and JK sands

[40] For the E–1, E–2 and F–2 sands, excluded both by Exhs. 21 and 40, Exh. 2 computes a combined productive area of 5,300 acres.

[41] I.e., all but the C–1 I, and L–1 sands.

[42] Formerly estimated to total some 202,527 Mmcf.

18.3 feet; C–1 sand, 9.1 feet; D–2 sand, 13.2 feet; D–4 sand, 26.0 feet; G–2 sand, 13.1 feet; I sand, 23.4 feet; I–2 sand, 26.7 feet; J–3 sand, 29.9 feet; and the L–1 sand, 35.2 feet. These selections yielded an overall average which is 95.6% of the foregoing Exh. 2 average of 24.6 feet.

Porosity determined in Exh. 2 to be a consistent 30%, is uniformly increased sand by sand in Exh. 40 to 32%, whereas in Exh. 21 Applicants' witness employs porosities which range from 29% to 32%.

The sands in this field are similar in type and Tennessee's witness assumed that each would have the same porosity. This witness also testified that while core analyses served as a good guide to porosity, the sidewall core, due to the manner in which taken from the sand, often gives a lower porosity than is actually present, and therefore, in effect, based these conclusions in part upon the results of similar analyses made from samples taken on the Shell Oil Company acreage which ran as high as 32% to 35%, and in part upon more reliable analyses of conventional or diamond cores of which he had available a fair amount for the Miocene sand in certain fields in southern Louisiana.[42] Applicants' witness particularly emphasized his use of electric log interpretations in such circumstances.

Using the volumes resulting from the previously selected area and thicknesses factors, *supra*, the porosities determined by Applicants' witness produce a weighted average of 30.3%, as compared with 30% of Exh. 2 and 32% in Exh. 40.

In accordance with the general principle of selection previously adopted the porosities determined in Applicants' Exh. 21 are generally appropriate and are therefor here selected.

In determining the interstitial or connate water percent, Applicants' witness considered all available core analyses but because the CATC cores were, as before, generally contaminated side-wall samples relied upon electric logs and judgment. He uses a lower percent than the Exh. 2, particularly for the C–1, D–2, and J–3 sands (15–18%), and a higher percent for the I sand (22%).

While Tennessee's witness had available 24 core analyses from the CATC and Shell Oil Company wells in the field he appears to have relied upon the interpretation of electric log data and a general knowledge of similar sands in the area. For instance, he had seen laboratory results of samples taken by other companies in similar type sands in various fields throughout the general area which ran within the range of 12% to 20%, and knew that Shell Oil Company also uses 12–15% with respect to Block 192 field. On this basis, apparently, he continues the use of a 20% connate water factor as in Exh. 2. A lower connate water percent has the tendency of increasing the reserve estimate while a higher one has the contrary effect.

The testimony of Applicant's witness is too general to support the varying percents which he uses and, accordingly, those established in Exh. 2 are not considered to have been impeached.

As before, Applicants' witness determines reservoir pressures by using measured pressures or, where such are not available, by using an established regional gradient to the average depth of reservoir; and, Tennessee's witness by using the actual initial reservoir pressure or a normal gradient curve derived from actual pressure surveys for the general area. The pressures in Exhs. 21 and 40 vary from those in Exh. 2 particularly for most of the deeper sands (below G–2) with the I sand exhibiting in Exhs. 2 and 40 a possible anomalous pressure-depth situation.

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[42] The same witness also stated generally that his increases were due to additional information and growing experience with respect to this type of sand throughout the general area.

The comparative average relationships in order of sand depths are as follows: [44]

Sands	Exh. 2 (Av. psi/ft)	Exh. 21 (Av. psi/ft)	Exh. 40 (Av. psi/ft)
B–15—G–2	0.466	0.468	0.470
I	.589	.490	.574
I–2, J–3, L–1	.542	.508	.523

With due regard to the pressure-depth relationships and the practical rule, hereinbefore adopted, of generally selecting data from Exhs. 21 and 40 which represent the least departure from that previously established in Exh. 2, and in the absence of justification for any other determination, the pressures for sands B–15, G–2, I, and J–3 are selected from Exh. 40 and for the C–1, D–2, D–4, 1–2, and L–1 sands from Exh. 21. Applicants' witness offers no justification for the use of an I sand pressure other than that which appears in Exh. 2 or Exh. 40. [45]

Temperatures are determined, as described in relation to the preceding fields, by actual measurements or from gradient curves. Applicants' witness' temperatures for the 4 upper sands (B–15 through D–4) are substantially consistent with those in Exh. 2. Tennessee's witness uses slightly lower temperatures for the D–2 and D–4 sands, along with a datum shallower than that indicated in Exh. 2 for the D–2 sand, and a temperature gradient smaller for the D–4 sand. With respect to the remaining 5 deeper sands Applicants' witness employs markedly higher temperatures due to an unsupported average 1.4° (F.)/100 ft. temperature gradient as compared with a 1.2° gradient in Exh. 2.[46] Tennessee's witness uses a gradient approximately equal to the 1.2° of Exh. 2 with no significant adjustments in datum depths. The result is that one expert in effect confirms the data of Exh. 2 for the upper sands and the other the data for the lower sands. In these circumstances, and in the absence of evidence requiring some other determination, the average reservoir temperatures of Exh. 2 and the accompanying temperature correction factors are retained.

The Exh. 2 deviation or compressibility factors for the upper sands (B–1 through D–4) are confirmed by one or the other of the two witnesses. Each witness arrives at some small increase for the G–2 and J–3 sands. While Applicants' witness reduces the factor for the I sand, Tennessee's witness confirms the Exh. 2 determination. The factor used in Exh. 2 for the I–2 sand is, in effect, unimpeached. Accordingly, these factors are selected as indicated, including that which accords with the agreed estimates for the G–2 and J–3 sands, along with that computed in Exh. 2 for the I sand and Tennessee's 0.99 for the L–1 sand.

Initial reserves in place for these 9 sands of the Block 192 field, computed by use of the foregoing selected factors, areas, and sand thicknesses, compare with the results of Exh. 2, 21, and 40, as follows:

[44] Cf., *Petroleum Reservoir Engineering,* Amyx Bass and Whiting (1960), specifically "Reservoir Pressures", p. 579, where it is stated that 0.465 psi/ft., is normal for the Louisiana and Texas Gulf Coast area.

[45] The sand is a tested sand. At the time of the preparation of Exh. 2 the sand had 1 completion and at the time of the two later exhibits, 2 completions.

[46] As to the nature of these gradients see the part of this decision above which deals with the preceding Block 71 field.

	By selected factors (Mmcf)	Exh. 2 (Mmcf)	Exh. 21 (Mmcf)	Exh. 40 (Mmcf)
Total gas in place	843,895	1,233,376	538,757	1,059,968
Percent index	68.4	100.0	43.7	85.9

Thus, Applicants' estimates of initial reserves in place are 43.7% and Tennessee's are 85.9% of those estimates in Exh. 2. While selected factors indicate a test possibility that Tennessee's reserves are 17.5% too high they deny support for Applicants' lower estimates.[47]

The conclusion to be drawn from the conflict of the expert testimony, the foregoing test results, and resulting reserve comparisions is that Applicants' estimates for this field which appear in the current exhibit are not supported by the evidence, and that an estimate lower than Tennessee's is not of necessity acceptable.

New Field and Sands

In addition to the sands originally appearing in Exhibit 2, Applicants' witness and Tennessee's include in their current estimates initial reserves for the Block 64 field, not established at the time of the earlier estimates, and for some 8 additional sands in the Block 71 and Block 192 fields. Due to incomplete supporting evidence, and absent a reference such as was available for the old sands in Exhibit 2, the question immediately involved is whether Applicants' mere listing of eight component factors in the instance of each sand is of itself sufficient to prevail over what amounts to a completely similar listing by Tennessee's witness supporting substantially different results.[48] In the light of the overall precedent results relating to the old sands the answer is necessarily in the negative.

The estimates of initial reserves for the new sands compare by fields as follows (14.73 psia):

Field block	Exhibit 21 (Mmcf)	Exhibit 40 (Mmcf)
64	44,750	141,810
71	50,931	49,500
192	21,326	62,393
Total	117,007	253,703
Percent index	46.1	100.0

Thus the percent index of 46% for the Exhibit 21 results for the new field and sands compares with the corresponding percent index of 57% for the old sands. On the other hand test results obtained by the selection of factors according to the methods hereinabove set forth, constitute an overall 87.07% of the results set forth in Exhibit 40. In the absence of supporting data, or indeed of any data permitting any other approach, the initial reserves accepted for the purposes of this decision as appropriate for the new field and sands will

[47] The difference between the result derived by the selected factors and those of Exhs. 21 and 40, respectively, are largely due to the areal and pay thickness considerations. With respect to Exh. 21 results, 80% of the difference is due to the selection of sand area and thickness while with respect to Exh. 40 71% of the difference is due to such selections.

[48] These component factors, as for the Exhibit 2 sands, are porosity, connate water, atmospheres, temperature correction, deviation, productive area, pay thickness and a recovery factor.

constitute the same relative percent as do the herein computed test results for those sands originally listed in Exhibit 2, and considered in the preceding sections of this decision.[49]

Except for the reserves recovered from the abandoned Block 49 field, the resulting totals of accepted initial reserves in place, old and new, and the comparable Exhibit 21 and Exhibit 40 total results are (14.73 psia):

Field block	Accepted (Mmcf)	Exhibit 21 (Mmcf)	Exhibit 40 (Mmcf)
49			
62	95,843	89,038	95,843
64—new	123,474	44,750	141,810
71—old	171,311	127,156	171,311
—new	43,100	50,931	49,500
192—old	1,059,968	538,757	1,059,968
—new	54,326	21,326	62,393
Total	1,548,022	871,968	1,580,825

Recovery Factors

Tennessee's witness supports the use of his percent recovery factors by testifying that the factor is based upon his judgment and general experience related to similar types of reservoirs. Applicants' witness supported his selection of recovery factors ranging from 80 to 85%, on the general basis of the capacity of wells, size and structural conformation of the reservoir, past production history, and anticipated future well performance. However, in no instance does either witness specifically support the use of any percent with respect to the claimed basis therefor.

Applicants' witness uses an 85% factor for each of the sands in the Block 62 field, Tennessee's witness a 75% factor, after having used 85% in Exhibit 2. No justification of substance appears for the change and accordingly 85% is here considered appropriate for use for this field.

For those sands in the Block 71 field, which appear first in Exhibit 2, both witnesses employ an 85% factor for the H–1 and I sands, reduced to 80% by Applicants' witness for the G–1 and I–4 sands, for which latter (I–4) Tennessee's witness employs 85%. For the newer sands (Applicants' N, P, and Q, or Tennessee's JN, KJ, and KM) Tennessee's witness employs 85% throughout, while Applicants' witness employs 85% for the N sand and, without explanation, an 83% factor for the latter two (P and Q). In the absence of further evidence an overall 85% factor is appropriate for the sands of this field.

With respect to the sands of the Block 192 field, Exhibit 2 established an 80% recovery for the shallower and an 85% for the deeper sands. Currently, Applicants' witness uses 80% for all sands while Tennessee's witness uses 85% for

[49] The computed test reserves are lower than the accepted reserves for reasons which are implicit in this method of checking which, it is to be said, has been adopted because of the absence of better evidence of record. Test reserves and Tennessee's Exhibit 40 reserves compare as follows (14.73 psia):

Field block	Test reserves (Mmcf)	Exhibit 40 reserves (Mmcf)
62	150,984	95,843
71	160,649	171,311
192	843,895	1,059,968
Total	1,155,528	1,327,122
Percent index	87.07	100.0

those below the B–15 and C–1 sands, for which latter he uses 80%. Thus, an 80% factor seems satisfactorily established for the upper B–15, C–1, D–2, and D–4 sands and an 85% recovery factor for the lower G–2, I, I–2, J–3, and L–1 sands. The new shallower sand (Applicants' I, or Tennessee's FL) and the two new deeper sands (Applicants' NO–1 and S, or Tennessee's HH and IS) should carry recovery factors consistent with those determined for the applicable general depth division—80% and 85% respectively.

Finally, a recovery factor of 85% as employed by Applicants' witness is appropriate for the Block 64 field.

Summary of Recoverable Reserves

On the basis of the foregoing recovery factors the accepted initial recoverable reserves compare as follows (14.73 psia):

Field block	Accepted (Mmcf)	Exhibit 21 (Mmcf)	Exhibit 40 (Mmcf)
62	81,467	75,668	71,884
64	104,953	38,037	113,447
71	182,249	149,300	187,689
192	936,646	448,012	949,901
Total	1,305,315	711,017	1,322,921
Percent index	100.0	54.5	101.35

Allowing for shrinkage and fuel losses the respective initial salable reserves become: [50]

Field block	Accepted (Mmcf)	Exhibit 21 (Mmcf)	Exhibit 40 (Mmcf)
62	81,467	75,668	71,884
64	102,854	37,276	111,178
71	181,474	148,665	186,891
192	922,681	441,332	935,738
Total	1,288,476	702,941	1,305,691

On the basis of the operator's computed past production, recoverable reserves remaining as of January 1, 1960, are:

Field block	Accepted (Mmcf)	Exhibit 21 (Mmcf)	Exhibit 40 (Mmcf)
62	74,506	68,707	64,923
64	96,501	29,585	104,995
71	165,626	132,677	171,066
192	907,730	419,096	920,985
Total	1,244,363	650,065	1,261,969

Allowing for the same shrinkage and fuel losses the various remaining salable reserves are approximately as follows:

Field block	Accepted (Mmcf)	Exhibit 21 (Mmcf)	Exhibit 40 (Mmcf)
62	74,506	68,707	64,923
64	94,571	28,993	102,895
71	164,922	132,113	170,339
192	894,196	412,847	907,253
Total	1,228,195	642,660	1,245,410

[50] Shrinkage factors by fields, approximate—Block 62, none; Block 64, 2.00%; Block 71, 0.425%; Block 192, 1.491%.

Annual and Daily Average Availability

Applicants' witness bases availability on his estimates of initial recoverable reserves and on provisions of the CATC-Tennessee contracts, except that for the year 1960 the availability represents the withdrawal estimated by the CATC companies.[51] Thus, his figure, in effect, of 87,866 Mcf of average daily deliveries for the period 1961–1972 substantially represents the contract daily provision of 1,000 Mcf per 8,000,000 Mcf of recoverable reserves applied to the current figure of 703,661 Mmcf of initial reserves of salable gas (Exh. 21; Sch. 1).[52] The evidence is that these availabilities do not exceed the total capacity of the wells to produce. On the basis of the contract daily provision, aforesaid, and the accepted initial salable reserves, daily deliveries would average 161,059 Mcf and on the basis of the average over a life of 20 years the delivery would be 176,504 Mcf per day.

The Contract Price—Development in Negotiations

As stated in the initial decision in the original proceedings in 1947 and 1948, the CATC companies acquired leases from the State of Louisiana on some 95,000 acres offshore Cameron and Vermillion Parishes, and by mid-1955 in the course of drilling seven shut-in wells on two blocks in the East Cameron (Blocks Nos. 49 and 71) and one block in the West Cameron Areas (Block No. 192) had discovered the existence of three multipay gas condensate fields with substantial reserves. Applicants were under some pressure to dispose of the available production in that they construed the terms of Section 6(a) of the Outer-Continental Shelf Lands Act of 1953 as applicable in the premises and to require either production by early August 1958 or continued drilling on and after that date and were advised as to the possibility of a leasee's implied covenant binding the CATC companies to use due diligence in marketing gas already discovered. Further, each of the companies needed current revenue particularly for developing other offshore leases and for further lease bidding.

Accordingly, in September 1955, Continental forwarded letters to nine major interstate pipeline companies having transmission facilities in Southern Louisiana advising of the availability for sale of gas production from up to 2 trillion cubic feet of the Cameron-Vermillion offshore reserves.[53] Tennessee responded on October 21, 1955, with a combination offer which included an initial price of 17¢ per Mcf, with escalation and tax reimbursement, for the West Delta reserves,[54] and an initial price for the Cameron-Vermillion area gas which was later revised to one of 17¢ plus an escalation of 1½¢ per Mcf each four years to 23¢ and tax reimbursement. The CATC companies severally accepted Tennessee's offer for the West Delta reserves but continued with further negotiations for the Cameron-Vermillion area gas reserves.[55] By June 18,

[51] For 1960—147,440 Mcf per day.

[52] On the basis of a uniform delivery over an assumed 20 year life the average daily volume becomes 96,392 Mcf per day.

[53] In its negotiations Continental in part contacted some 20 pipeline, gathering, chemical, manufacturing, and electric generating companies, 15 of which expressed interest in purchasing the gas either in the field where produced or at a point outside the field. Tidewater contacted Coastal Transmission Corporation, among others, in April 1955, and otherwise investigated the various possibilities of disposal. Atlantic first mentioned the matter in April 1955 to United Gas Pipe Line Company and later to Tennessee.

[54] The upper limit of the West Delta reserves was then considered to be some 1.5 trillion cubic feet.

[55] Applicants' acceptance was based substantially on the fact that no other offer as attractive price-wise had been received, Tennessee refusing to increase its price due to triggering considerations.

1956, some six interstate pipelines had made offers considered to be substantial,[56] but which differed variously as to price; the proposed date of first delivery from which the take-or-pay obligations would commence; the first year's take-or-pay quantity; daily minimum and maximum volumes; make-up periods; delivery points;[57] delivery pressures; and metering obligations. Other than Tennessee's later offer (21.4¢ per Mcf plus tax reimbursement), initial prices varied from a low of 18¢ to a high of 21¢ per Mcf (15.025 psia) plus tax reimbursement. Fixed 5-year escalations ranged from 1¢ to 2½¢ per Mcf, and some offers included favored nation and price redetermination clauses.

Finally, on or about July 12, 1956, Applicants accepted Tennessee's offer principally because, in addition to the price, the latter agreed to accept additional commitments of Cameron area reserves;[58] build lines to the location of the additional reserves;[59] accept deliveries at 700 psia; carry ashore, for a fee, gas over and above the deliveries from reserves committed; and to permit Applicants to supply up to 50,000 Mcf of additional gas per day should West Delta deliveries be reduced because of cycling operations in that field.

The testimony in these overall proceedings is to the effect that there was no affiliation at the time of the negotiations between the CATC companies and Tennessee and that the CATC contracts resulted from arm's-length bargaining.[60]

Interveners reject arm's-length considerations on the ground that oil for househeating, and commercial and industrial uses constitutes, generally, the principal competition for gas and that producers therefor have an incentive to increase gas field prices and fuel prices or to increase gas field prices alone so that oil might encroach on the gas market. However, it appears among other things that fuel oil production is controlled principally by the general refining of gasoline, but in any event there is no evidence to support these conclusions of the witness. Neither arm's-length bargaining nor the incentive referred to constitutes a real issue in this proceeding.

Contemporary Field Price Pattern

None of the contract prices available of evidence can be directly compared with the proposed price in that at the time Tennessee negotiated the CATC contract the assumed volume of reserves was larger than any which had been committed to that time by a single contract.

Applicants' evidence is that certificated contracts for gas purchased in the Erath Field, Acadia Parish, Louisiana, by United Fuel Gas Company, executed some four years before the CATC contracts, carried initial prices of 20¢ per Mcf plus tax which, with fixed escalations, would have provided a total price by the date scheduled for the commencement of the CATC deliveries of 20.6% per Mcf; that contracts[61] for gas purchased from two fields in Southwestern Louisiana by American Louisana Pipe Line Company, executed in June and July 1953, with first deliveries in August 1956, carried initial prices of 20¢ per Mcf with fixed escalations; that contracts for gas purchased in East Lake Palourde Field, Assumption Parish, Louisiana, by Texas Gas Transmission Corporation,

[56] That by American Louisiana Pipe Line Company, Southern Natural Gas Company, Tennessee Gas Transmission Company, Transcontinental Gas Pipe Line Corporation, United Fuel Gas Company, and El Paso Natural Gas Company, respectively.

[57] Central point in field or at each production platform.

[58] Including an additional trillion cubic feet by August 1, 1958 and 400 billion cubic feet each 12 months following for 10 years.

[59] At a specified ratio of miles of line to the volume of additional reserves.

[60] The recent testimony is in the present tense. However, testimony in the original proceeding is of a supporting nature.

[61] The Erath contract was somewhat flexible, allowing a minimum daily quantity of 50% and a maximum daily quantity of 150% of the contract quantity as compared with the CATC minimum and maximum of 66⅔% and 125%, respectively.

executed in April 1955, with first deliveries in December 1956, carried initial prices of 20¢ per Mcf plus tax, with fixed escalations; and, lastly that contracts executed by United Gas Pipe Line Company, in the latter part of 1954 for gas from the Pistol Ridge-Maxie Field, Forrest County, Mississippi carried initial prices of 20¢ per Mcf. At the time of the negotiation of the CATC gas contracts with Tennessee, United Gas Pipe Line Company was also paying 21.2¢ per Mcf in the Duck Lake Field, Louisiana, and Olin Gas Transmission Company was paying 21.4¢ per Mcf in the Bateman Lake Field, Louisana, for a nonjurisdictional use.

Applicants' further evidence is that prices for gas purchased in Southern Louisiana since the execution of the CATC contracts have been substantially higher ranging from 23.55¢ to 24.8¢ per Mcf,[62] and it is the opinion of Tennessee's senior vice-president in charge of gas supply that CATC gas would currently bring more than the proposed 21.4¢ plus tax.

The foregoing evidence goes little further than to establish that several pre-CATC contract initial prices were at the 20¢ level.

Further evidence submitted on behalf of Applicants discloses that of a total of 68 Southern Louisiana contracts dated from July 1, 1954 to June 30, 1956, 25 carried an initial price of 16¢, 17 a price of 17¢ and 5 a price of 20¢ per Mcf, with the median of the high 10% being 20¢ per Mcf.

Interveners' case premises that the cost data presented in these proceedings, relating primarily to the limited area of the CATC Cameron leases, is too restricted to be useful and that in order to test the CATC price resort must be had to area price data.[63]

Interveners' case assumes, however, that the area price determination is to be made as if the present record had been available when the case was first before the Commission in early 1957, and that prices subsequently certificated in other proceedings involving sales in Southern Louisiana are not applicable to this proceeding, on the principal ground that post-CATC prices are substantially infected with the alleged illegality of the original CATC prices.

Interveners made a study of initial base prices[64] in some 290 producer rate schedules having at least a 10-year contract term and pertaining to interstate sales from fields located in Southern Louisiana.[65] The underlying contracts are dated from January 1, 1950 through December 31, 1956, when prices rose from an initial base price level of 8¢ to 9¢ per Mcf in 1950 to the 20¢ levels prevailing at the time of the execution of the 20-year CATC contracts.

According to the Interveners' evidence four Southern Louisiana contracts had, prior to the 1956 CATC contracts, severally initiated a new and higher price which achieved a so-called "break-through" to a higher level or plateau.

The first such movement instanced by Interveners was that effected in a contract executed by Southern Natural Gas Company in 1951, in connection with a major system expansion from a capacity of 670,000 Mcf per day to 1,020,000 Mcf per day, which provided an initial base price of 12¢ per Mcf as compared with a previously prevailing price of 9¢ per Mcf. Interveners' witness' opinion that

[62] The evidence on this matter relates to four contracts at 23.55¢, one at 23.8¢, and one at 24.8¢, including tax reimbursement. Whether any of these has been suspended does not appear.

[63] A pricing area consisting of Southern Louisiana including the off-shore region, although the contracts available relate almost entirely to on-shore sales.

[64] The initial price when the contract was signed, not here including the tax reimbursement.

[65] Including fields in Louisiana parishes lying on or south of latitude 31° north. A given contract will result in a multiple filing of separate rate schedules depending upon the number of jointly contracting producers. Hence the number of rate schedules are no indication of the number of contracts executed.

this increase was substantially due to Southern's relatively short transmission system having a relatively low transmission cost which minimized the competitive pressure of other fuels on the field price for gas is not supported by a presentation of fact.

The second movement instanced by Interveners occurred particularly in the second and third quarters of 1952, as effected in contracts negotiated for the United Fuel Gas Company-Gulf Interstate Company project of the Columbia Gas System to supply an 860 mile 30-inch line having an initial capacity of 375,000 Mcf per day. Of the required supply some 100,000 Mcf per day was contracted for in the Erath field, Louisiana, at an initial price of 20¢ per Mcf, and the remainder in 15 other southern Louisiana fields having relatively smaller reserves at initial base prices of 16¢ per Mcf.[66] During this period other producers were buying gas at a price lower than 16¢.

The third movement, similarly instanced, occurred primarily in the second quarter of 1953 in contracts negotiated to provide the initial gas supply for American-Louisiana Pipe Line Company (American-Louisiana), then newly formed to bring additional gas into the area served by Michigan Consolidated Gas Company and Michigan Wisconsin Pipe Line Company.[67] American-Louisiana's pipeline was designed to operate at an initial capacity of approximately 300,000 Mcf per day against which approximately 250,000 Mcf was purchased in southern Louisiana at initial prices, depending upon the contract, of 17¢, 18¢ and 20¢ per Mcf.

However, during 1954 and the first quarter of 1955 the highest initial contract price in the area was 17¢ per Mcf, with most prices placed at 16¢ or below.

The last movement instanced by Interveners came in the second quarter of 1955 in 20¢ contracts entered into by Texas Gas Transmission Corporation (Texas Gas) for a gas supply for its 110,000 Mcf per day expansion program. Sources were so selected as to avoid the triggering of favored-nations' clauses in substantial contracts previously negotiated by Texas Gas.[68]

Interveners contend that except for those contracts which were influenced by the United Fuel-Erath field transaction, 16¢ had become a virtual ceiling for area prices in the pre-CATC period. This view of the action of the 16¢ price is compromised by evidence to the effect that by June 30, 1954, a majority of initial prices were at a level of 16¢ or above and by June 30, 1956, the 16¢ was in fact a floor.[69] Of some importance in appraising Interveners' study is the further fact that prices current in 1951 and 1952 afford an uncertain basis upon which to judge the nature of the price rise to 20¢, as during those years, and until March 12, 1953, regulations of the Office of Price Stabilization limited to some degree new field prices charged by a producer to the highest price charged by him in a particular market or producing area during the base period December 19, 1950, to January 25, 1951.

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[66] The line was certificated May 20, 1953 (12 FPC 115). OPA regulation of gas prices prevailed until March 12, 1953. The average initial base price of all gas so purchased was 17¢ per Mcf. The contracts contained fixed escalations, favored-nations clauses, and, except for Erath, periodic renegotiation provisions.

[67] Because of the price increases reflected in the preceding Columbia Gas System Erath contracts Interveners' witness questions these later American Louisiana contracts as representing a "break-through" but includes them in view of the fact these failed to provide certain non-price benefits contained in the former.

[68] According to the witness, Texas Gas suffered a triple handicap in its negotiations; its own favored-nations situation, and the results of the United Fuel gas contracts and the American-Louisiana contracts in fixing higher levels for initial base prices. The Texas Gas contracts also failed to provide certain advantageous non-price provisions contained in the earlier Columbia System Erath contracts.

[69] In the second quarter of 1956 the average price weighted by 1958 volumes had become 18.22¢ per Mcf, increasing from 16¢ for the third quarter of 1955.

On the basis of Interveners' plot of the initial base prices in 1950–1956 southern Louisiana rate schedules, and relying on the array of prices to average out varying conditioning factors,[70] Interveners' principal price witness testified that the most prevalent price for new contracts in his selected 1953–1956 period[71] was 16.0¢ per Mcf (15.025 psia), which he testified represented in his opinion a solidly established price level and a reasonable price expectation for producers during the period.

Interveners' principal price witness did not directly relate cost trends to price trends. Though generally aware that inflation in labor and material costs could have had an effect on a producer's cost of service, he made no independent study of what increases in cost may have so occurred in connection with the discovery and production of oil and gas. He did obtain from a general construction index an 8.5% increase in the index between January 1, 1955 and June 1, 1956,[72] from which he reasoned that the price line could have been established as of the latter date at 17¢ per Mcf (15,025 psia) before tax.

Interveners added a 1¢ State severence tax to their prices. While this tax is now 2.3¢ with the amount reimbursed by the purchaser ranging between 1.754¢ (75%) and 2.07¢ (90%) of the tax imposed, in view of the off-shore land title controversy it is possible that no tax will apply to at least a substantial portion of the gas sold under the CATC-Tennessee contracts.

It would appear that in the preparation of Interveners' price data (Exhs. 41 and 42) treating each schedule filed as a separate contract without taking into account the difference between a multiple-party sale and the multiple rate schedules filed by the vendors compromises the use of these exhibits for the purpose of establishing a price trend to a degree which cannot be determined, and, indeed, Interveners' principal price witness indicated some significant doubt as to the reliability in question because the exhibits did not allow for either the related possible non-filing by multiple party signatories or for the possible filing of a ratification of a sales agreement as a rate schedule. Testimony attempting to rehabilitate the exhibits on the basis of the witness' general statistical feel for numbers is an inadequate substitute for an erroneously prepared exhibit.

Price Effects on Tennessee

At the time of the execution of the CATC contracts Tennessee anticipated that the derived weighted average cost of gas to Tennessee of 12.54¢ per Mcf in 1957, without Cameron deliveries, would be increased to 12.71¢ with the then expected November and December deliveries of Cameron gas, or by 0.17¢ per Mcf, and that, similarly, on the basis of 12 months delivery of Cameron gas, in 1958, such costs would increase from 12.73¢ to 13.70¢ or by 0.97¢ per Mcf for that year.[73]

In fact, for 1957 the weighted average cost of gas, with no Cameron deliveries to consider, was actually 12.63¢ per Mcf; and, for 1958, with 6 months actual Cameron deliveries 13.15¢, as compared with a derived weighted average cost, without the Cameron gas, of 12.92¢ per Mcf—a partial difference in that year of 0.23¢ per Mcf.[74]

[70] Such as those concerning contract terms, reserves and deliverability, delivery conditions, swings, distance from the pipeline, pressure, and quality of the gas. Due to the few offshore sales available onshore sales had to be resorted to for establishing the price line.

[71] Selected to iron out the 1954 low with the 1953 and 1955 highs.

[72] Or 13.2% for January 1, 1954, to January 1, 1958, and 17.4% to January 1, 1960.

[73] Assuming for this purpose deliveries of 240,000 Mcf (14.73 psia) per day from the CATC Cameron acreage.

[74] However, on the improbable assumption that CATC gas could be replaced in 1958 (and 1959) at Tennessee's average cost.

Again, for 1959, the weighted average cost was 15.20¢ per Mcf against a computed 14.76¢ if the CATC Cameron deliveries were not included,—a difference of but 0.44¢ per Mcf (14.73 psia).[75]

While the 1957 variation between the CATC price and Tennessee's weighted average cost of gas was 169.4%,[76] in cases involving construction costs of more than $700,000 where, in the period January 1, 1950 to July 1, 1959, 85 certificates were granted by the Commission to the 23 major pipelines which, in the aggregate, purchase over 90% of the field gas purchased by reporting pipelines, initial prices for new gas have averaged from 66% less to 138% more than the pipeline's weighted average cost of gas. However, to apply such considerations in judging the propriety of prices proposed for new gas would simply mean that in seeking new reserves companies with a lower weighted average cost of gas would be penalized as compared with those new pipeline companies which have a higher weighted average cost of gas.[77]

The West Delta Contract Price

The CATC contracts with Tennessee of January 1956, dedicating West Delta reserves carried an initial base price of 17¢ per Mcf, plus the reimbursement of the Louisiana gathering tax.

The factors affecting the price offered by Tennessee for the West Delta gas, and accepted by the CATC companies, were particular. As compared with the Cameron area leases which are at a distance of 20 to 30 miles from the coast in some 50–57 feet of open water (average well 54 feet) where platforms are required to produce a well, the West Delta acreage lies within 10 miles of shore in some 5–57 feet of water (average well 25 feet) and is more or less protected by the Mississippi River delta.[78] Further, the 17¢ offer for reserves up to 1.5 trillion cubic feet represented in fact a level which had been fixed in earlier transactions between Tennessee and other producers with respect to a specified contract area which included offshore reaches of the West Delta Area,[79] and a limitation imposed by Tennessee's knowledge that a higher price for this gas would trigger the favored-nations provisions of the earlier contracts respecting large supplies located in 18 or more fields in

[75] Due to a change in the purchase pattern and increases from price redetermination effective as to Texas and Southwestern Louisiana purchases, which were not dependent upon the CATC-Cameron contracts, the computed weighted average cost of gas to Tennessee of non-Cameron gas increased from 12.63¢ per Mcf in 1957 to 14.76¢ per Mcf in 1959. Using the actual purchase pattern of October 1959, and a 15.025 psia pressure base, Tennessee's system-wide weighted average contract price as of November 1, 1959 for its Texas and Louisiana purchases, after the price redeterminations, without the Cameron gas, equals 17.69887¢ as compared with 18.24217¢ including the Cameron gas, for a difference of 0.54330¢. Confined to Louisiana purchases the weighted average non-Cameron contract price becomes 22.61685¢ as compared with the weighted average Cameron price of 21.85918¢.

[76] The ratio of the 21.4¢ per Mcf to Tennessee's weighted average cost before CATC deliveries of 12.63¢ per Mcf.

[77] The weighted average cost of gas to American Louisiana Pipe Line Company was 19.0¢ in 1957. Its purchase of gas priced at 21.4¢ would have meant a variation of but 112.6%.

[78] Average depth of water over dry holes was approximately equal: West Delta 44 feet Cameron 48 feet.

[79] The area is defined in Tennessee's contracts as a favored-nation area and extends seaward to the state boundary or 3-mile line, including the CATC West Delta Blocks Nos. 52, 53, 54, 55, and portions of 56 and 84, landward of the 3-mile limit. Four other CATC blocks are seaward of the 3-mile limit. The contracts contain quinquennial escalations as well as redetermination and favored-nation provisions.

the basic five-parish area.[80] The CATC companies had no other offer as attractive as Tennessee's, particularly as to the matter of early takes,[81] and, as about 75% of the CATC West Delta gas was produced and flared as associated oil well or casinghead gas, were confronted with the possibility of operating under future State shut-in or recycling orders.

Triggering

The evidence is beyond dispute that as of the time of execution of the CATC-Tennessee contracts the Cameron-Vermillion areas were considered by Tennessee and by the CATC companies to lie beyond the range of the favored-nation provisions of contracts executed by Tennessee in the 5 parish area of Southeastern Louisiana.[82] Tennessee's particular and early concern in its continuing negotiations for the CATC-West Delta and Cameron production as to the triggering effects on contracts in its 5 parish area and the explicit testimony of Tennessee's senior vice-president in charge of gas supply, and others, categorically negative the possibility that the CATC contracts would trigger Tennessee's favored-nation clauses in its other gas purchase contracts.

Indeed, since the time of initial deliveries under the CATC-Cameron contracts in July 1958, no seller has asserted under any other Tennessee gas purchase contract any claim to a favored-nation price increase based upon the CATC-Cameron area price;[83] and there is no evidence of triggering as to another purchaser's contract.

Alternative Markets

Contemporaneously with the 1955–56 consideration of a jurisdictional sale, and again as late as June 1957, the CATC companies considered the possibility of making a direct consumer sale at Lake Charles, Louisiana, where Continental and Cities each had an oil refinery and were also owners of Cit-Con Refinery and Petroleum Chemicals, Inc.[84] It was estimated that, including various existing short term gas purchases commitments, Lake Charles users would require approximately 129,000 Mcf daily in 1957, 196,000 Mcf in 1958 and 1959, and 348,000 Mcf in 1960, increasing to some 672,000 Mcf by 1976, with an estimated net re-

[80] These parishes are: Assumption, Terrebonne, La Fourche, Jefferson and Plaquemines, lying in southwestern Louisiana. The contracts included those executed by Tennessee with the following producers on the dates stated—The California Company, April 1, 1955, and later (11 fields in 3 parishes); Shell Oil Company, March 29, 1955 (4 fields in 2 parishes); The Superior Oil Company, April 6, 1955 (2 areas in one parish); Mayfield, et al., April 1, 1955 (1 field in 3 parishes), and subsequently some three or more others.

[81] The area was located convenient to Tennessee's newly constructed Muskrat line which extended along the southern limits of the Louisiana Delta coast and which had available capacity. The role of costs in fixing the level at which the CATC Applicants started their negotiations is not disclosed. As of December 31, 1959, in the CATC Marine Region, Applicants had drilled or particapated in the drilling of 15 wells and 10 dry holes in the West Delta Area against 26 wells and 13 dry holes in the Cameron area. Cameron average well costs were 23.4% higher, average dry hole costs 2.3% higher, and average gas lease operating expense 3.8% higher than corresponding figures for the West Delta wells (13% deeper) and dry holes (20% deeper) which figures, however, standing alone are not conclusive.

[82] The favored-nation area in the West Delta contract in terms did not include the offshore Cameron area.

[83] Prices agreed to in 1959 price determination procedures under Tennessee's Louisana contracts were not affected in any way by the CATC contract prices.

[84] Both Continental and Cities were willing to purchase the production from Atlantic's and Tidewater's reserves.

quirement of the CATC companies of 26,000 Mcf per day in 1957, 93,000 Mcf in 1958 and 1959, and 329,000 Mcf in 1960,[85] increasing to 672,000 Mcf by 1976.[86]

No firm prices were determined upon with these related interests, but in 1956 the latter were paying delivered prices of 13.5¢ and 17.5¢ per Mcf which were expected to increase as the level of the weighted average cost of gas to the pipeline vendors also increased.[87]

The CATC companies, however, would have to had to construct the pipeline from the offshore fields to Lake Charles at some undisclosed cost, and this approach was considered desirable only as a method of protecting the CATC leases.

Further, commencing March 9, 1956, Continental took steps looking to possible negotiation of a sale of the CATC gas to certain industrial concerns then considering the location of plants along the Mississippi River in the Baton Rouge-New Orleans area, including the Dow Chemical Company, Kaiser Aluminum Company, Wyandotte Chemical Corporation, and Gaylord Container Corporation, as well as Louisiana Power and Light Company, which latter expected to have a new electric generating plant in operation sometime in 1960. Although the new industrial plants would have had substantial requirements,[88] all of these were either in various stages of planning or early stages of construction, and could not have been ready to take the gas by the aforesaid critical date of August 7, 1958.

The CATC companies also tentatively negotiated, both prior to August 1956 and during April 1957, for the sale of their entire production to industrial users in Arkansas,[89] at takes generally comparable to, and at a price schedule competitive with, Tennessee's, but this arrangement would have resulted in some delay in sales reaching full market volumes and in receipt of revenues.

A study of major industrial markets within a 400 mile radius of the Cameron area,[90] submitted in evidence on behalf of the Applicants, discloses that in the opinion of the witness substantial alternate market outlets were available to the CATC group in 1956, and that there are at least 12 market areas of suffi-

[85] Here matching Applicants' estimate of available offshore supplies.

[86] Applicants' more recent estimates, based on a downward revision of estimated production from the Cameron properties and some elimination of assumed plant expansion by Petroleum Chemicals, Inc., compare as follows:

	Requirements as percent of offshore-CATC supply	
	1956 estimates (percent)	March 1960 estimates (percent)
1957	61	53.
1958	50–55	76.
1959	48–50	65.
1960	Over 100	Over 100.

[87] Thus, the 13.5¢ was expected to increase to 18.5¢ in 1957 and by about 1¢ per Mcf a year thereafter. In fact the Lake Arthur plants paid 18.64¢ and 18.87¢ per Mcf in 1957, 20.16¢ to 22.93¢ in 1958, and 21.83¢ to 23.6¢ in 1959. This market was available to Applicants through June 24, 1957, the date of the Commission's third and final order in the preceding stages of this proceeding.

[88] The Dow Chemical Company's operation at Freeport, Texas, as an example had estimated daily requirements of some 235,000 Mcf.

[89] With delivery to be made to Arkansas-Louisiana Gas Company in the field. The competitive price would have been within perhaps 1¢ per Mcf of the Tennessee price. A limited quantity of gas could also have been sold to Central Louisiana Electric Company for use in power generation provided other markets were obtained and the gas was delivered at plant.

[90] The range of the CATC negotiations above set forth.

cient size to absorb deliveries approximating the 100,000 Mcf per day assumed as an average of the magnitude of the CATC-Cameron production.

In summary, in the absence of firm commitments in relation to the foregoing alternative negotiations it can be concluded only that the best that Applicants could have expected from the intrastate market was a price which would have approximated 18.87¢ per Mcf in 1957, the year in which initial deliveries were intended to be made to Tennessee under the original provisions of the contracts of August 1956, less a cost of transportation.

Price in Relation to Trends—Market Projections and Drilling Trends

Applicants' first witness on the subject of prices in relation to trends in gas requirements obtains an estimate of the 1960–1964 increase in local demands upon reserves of natural gas in Louisiana and Texas by projecting 1946–1958 data derived from Louisiana and Texas historical market developments, including the witness' survey of industrial sales,[91] correlated with data pertaining to the relative characteristics of the various components of local market demands including those of the residential, commercial and mixed industrial sections. He obtains a corresponding estimate of the increases in national demands [92] upon the same reserves, using generally accepted growth forecasts for the national markets,[93] and related economic data, assuming that the proportion of production from reserves located in Louisiana and Texas which went into the interstate market in 1958 (61.263%) will hold in the future. He further assumes that annual new reserves plus extensions and revisions will continue to average the 14.4 trillion cubic feet attributable to the four years 1955–1958;[94] and that reserve additions must, at a minimum, provide each year for the equal replacement of those used to serve the existing markets and a 14 years supply for the year's expansions.[95] On the basis of all the foregoing, the witness estimates that Texas and Louisiana market consumption will increase at a minimum from approximately 6.2 trillion cubic feet in 1960 to 7.2 trillion cubic feet in 1964 and that the interstate market consumption supplied by the two States will increase likewise from about 8.2 trillion cubic feet in 1960 to at least 10.5 trillion cubic feet in 1964, and concludes that on a minimum basis the deficiency in annual additions with respect to requirements will amount increasingly to 3.3 trillion cubic feet by 1964 or 23.24% of the assumed reserve additions.

The witness further testified that the Louisiana and Texas markets will constitute an increasing portion of total demands upon the reserves of the two states, and his ultimate conclusion is that current gas prices are inadequate to stimulate the accelerated exploration and development to provide the additions necessary to meet the market requirements which might reasonably be expected in even the immediate future.

It is to be observed that in 1959, total additions to proved Texas and Louisiana reserves amounted to 18,726,591 Mmcf, a figure which is not only 30% higher than the witness' assumed 1955–1958 average addition but which, if sustained, would yield a life of 15.8 years for additions for use in connection with load growth as compared with the 7.8 years resulting from the witness' assumption that annual additions would continue at the 1955–1958 average of 14,394,421 Mmcf.

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[91] Consulting statistics published by the U.S. Bureau of Mines, and information available from official state sources and bureaus of business research of state universities, as well as from chambers of commerce, industrial associations, and individual industries.

[92] Of the United States generally but excluding Louisiana and Texas.

[93] Those of the American Gas Association (1958–1964) converted to rates and applied to Bureau of Mines data.

[94] Which was the highest of any four years in the post war period.

[95] In fact a 14 years supply is not equal to 14 years of deliverability but rather to some 10 years of deliverability.

In relation to the foregoing, and consistent therewith, it independently appears that even over a period as recent as 1951–1958, the average annual rate of increase in total consumption has been 9.1% for the Eastern States or 6.2% for the United States as a whole, and that the rate, which may be expected to decline with the relative completion of construction of lines to new markets, may be expected nevertheless to equal or exceed prospectively 5% per year.

Moreover it also appears that in the Southwestern States and in the United States as a whole market demand has increased more rapidly than have new discoveries, extensions and revisions, reported by the Gas Reserves Committee of the American Gas Association. Indeed, excepting in Louisiana, these show a decline relative to net production.[96]

At the same time the number of wells drilled, which increased at first in all the producing areas have since declined (1957–1959), so that, depending upon the area, it appears that wildcat drilling has fallen (1959) to between 63% and 77% of 1956 drilling, and development drilling to between 87% and 97%, except again, in Louisiana development drilling declined only in 1958. While the falling off in drilling is a matter of some importance in relation to the predicted increase in market requirements, its effect cannot be appraised without reference to following sections of this decision which refer to trends relating to drilling costs and productivity and the success ratio.

Trend in Productivity of Drilling

Applicants' evidence is to the effect that there is operative a primary long term trend for exploration to yield less, as disclosed in an indicated decline in the productivity of drilling and the tendency for the ratio of dry hole to total footage to increase,[97] and for the average size of new fields (gas and oil)[98] and for new discoveries of natural gas relative to wildcat footage to decline.[99] Applicants' evidence is to the further effect that while methods of exploration and production have been improved principally in the matters of geophysics, secondary recovery, and well spacing, the trend with respect thereto has been gradual and no marked improvement therein is in prospect for the foreseeable future.

[96] Indicated by the more or less continuous decline in the ratio of new supplies to net production as follows:

	1951	1958
Seven Southwestern States	2.19	1.67
United States	2.01	1.65
Cf., Louisiana	1.41	2.56

[97] The U.S. ratio of wildcat dry hole to productive wildcat footage increased from 560% in 1947–1949 to 645% in 1957–1959, while the ratio of development dry hole to productive development footage increased from 23.3% to 30.5% on the same basis. The relative higher success in the deep drilling is encumbered with higher drilling costs except where the reserves added are also relatively larger.

[98] New fields with reserves in excess of 6 billion cubic feet of gas or 1 million barrels of oil declined as follows:

	Gas fields (percent)	Oil fields (percent)
1943–1945	53.6	27.4
1951–1953	42.7	21.6

[99] Not including extensions and revisions. New discoveries have declined since 1947–1959 at an average annual rate of 4.6%, despite the fact that wildcat footage drilled has increased in greater proportion.

Interveners' evidence is to the effect that since 1955 there has been a reversal of direction of the trend in productivity and is contradictory of the findings of Applicants' witness that the industry is in a state of decline in the relation of productivity to drilling. Interveners' witness, does not recommend the employment of such trends for forecasting the productivity of drilling and accepts as a characteristic of the industry a probable declining primary trend in this ratio.

While the decline (oil and gas) in Louisiana has been negligible,[100] in the seven Southwestern States annual gross additions of oil and gas reserves (Btu basis) per foot drilled have been in a downtrend since 1947 to 1958[101] and the average rate of decrease, on a trend basis, has been at least 4.3% per year,[102] matched by a similar decline for the United States (3.8%), the three Southwestern States (4.5%),[103] and Texas (7.5%). As a result of these declines (oil and gas), in 1958 the trended average productivity of drilling was 68% of the 1947–1949 average for the United States, 64.2% for the seven Southwestern States, 63.3% for the three Southwestern States, 98.6% for Louisiana and 45.9% for Texas.

The productivity of drilling index for gas shows a smaller but still significant decline, except in Louisiana where productivity has in fact substantially increased in the period (1947–1958).

As between the average of the indices for 1952–1953 and the index for 1956 it appears that the declines (oil and gas) were 12.7% for the United States; 14.7% for the three Southwestern States; 14.4% for the seven Southwestern States; and negligible for Louisiana.

The conflict between the two witnesses concerns basically the method of trending. To obtain a trend for the data relating to annual additions of oil and gas (Btu) and to annual well footage drilled, respectively, Applicants' witness employs the straight line method placing the line by the method of least squares, while Interveners' witness by inspection selects a parabolic trend, the parabola being placed by the same least squares method.

The conflict concerning trends can best be resolved for the purposes of this proceeding by accepting Interveners' witness finding of a recent uptrend and concluding, on the basis of recent past experience, that for that portion of the future to which the findings in this decision may properly relate any recent uptrend will be effectively offset by at least a relatively equal decline.

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[100] Louisiana, 0.1%. As of 1958 drilling for 12 years past had been nearly three times more productive in Louisiana than in Texas.

[101] Arkansas, Kansas, Louisiana, Mississippi, New Mexico, Oklahoma, and Texas. Reserve additions as reported by the joint American Petroleum Institute-American Gas Association Reserves Committee; drilling footage from World Oil magazine, service wells excluded. It is here assumed that reserves added, which include also extensions and revisions of estimates of previous years' explorations, are related only to the drilling of the year in which additions, extensions, and revisions are reported. Footage drilled cannot be directly related separately to new supplies of natural gas, oil, or liquids, and here has to be allocated to gas. However, Applicants' witness testified there is no basis upon which wildcat footage can be allocated, as results are no gauge of the managerial intent which led to the drilling, and he, therefore, considered all such footage to be assignable to gas. Development footage was allocated on the basis of drilling results in the instance, separately, of oil wells, gas and condensate wells, and dry holes—using as to oil wells an assumed 1.5 Mcf/bb, of associated gas recovered, and as to gas wells 2.5 gals./Mcf of natural gas liquids recovered.

[102] Accumulating to a total of about 39% (1947–1958), without taking into account the lag between drilling activity and additions to reserves.

[103] Louisiana, Mississippi, and Texas.

Drilling Cost Trends

Applicants' oil and gas industry indices indicate that with reference to a 1947–1949 base,[104] there has been a sharp increase in production wages,[105] cost of casing,[106] and a weighted composite cost of casing, special contract services, drilling mud, labor, rock bits, and equipment.[107] The increase between the average of the 1952 and 1953 [108] indices and the 1956 index amounting to 23.9% for casing, and 16.9% for the composite items including 15.3% for wages.

Applicants' witness combines an index for operator drilling costs derived from nation-wide data for cost of labor, materials and services by weighting [109] with a generally undefined index of contract drilling rates to get an index of drilling costs per foot at constant depth. The witness in turn combines (multiplies) this latter index, with (by) an index based upon 1956 costs per foot weighted by depth to get an index of drilling costs as affected by the increasing depth of drilling. The final result indicates that by 1958 there had been an increase in this oil and gas drilling cost index which, in each of the above-mentioned areas and based upon 1947–1949 as 100, amounted to at least 40% with that between the 1952–1953 average and 1956 amounting to the following percents: United States 13.0%, three Southwestern States 17.9%, seven Southwestern States 13.9%, and Louisiana, 39.8%.

Combining the above referred to indices of productivity and of changes in cost of drilling as affected by depth the witness obtains composite results which indicate increases in drilling cost per unit of reserves (oil and gas) ranging from 29.2% for the United States to 40.5% for Louisiana; or for natural gas on an attributed footage basis ranging from 19.8% for the United States to 30.9% for total Louisiana.

Applicants' witness' index results as to drilling costs per foot and per unit of reserves are all dependent upon the validity of the results obtained by way of an index of changes in drilling costs based upon changes in depth,[110] and the

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[104] Incidentally, a period of relatively depressed prices for natural gas.

[105] From U.S. Department of Labor data, Monthly Labor Review.

[106] U.S. Department of Labor data, carbon steel oil well casing.

[107] Cost Study Committee Report (1959), Independent Petroleum Association of America, contrasting with a decline in the contract drilling rate.

[108] The first definite upward movement to natural gas prices after the 1947–1949 period of relatively depressed prices occurred in these two years, which are also those years immediately prior to the June 1954 decision of the United States Supreme Court in the so-called *Phillips* case relating to the jurisdiction of the Commission with respect to natural gas producer prices.

[109] In the ratio of 1954 nation-wide drilling rates to nation-wide operator drilling costs, i.e., 46% and 54%, respectively. A different weighting is used for Louisiana data.

[110] Interveners' witness took exception to Applicants' witness' index of drilling cost per foot on grounds which relate severally to each of the component indices: (1) the operator's cost index of labor, materials, and services; (2) the contract drilling rate index; (3) the index of drilling costs per foot at constant depth—a combination of the preceding two by use of weights; and (4) the index of cost change resulting from changes in depth. The witness excepts, *as to the first index*, on the grounds that the operator's cost index involves the weighting of component costs year by year by the proportions indicated for 1959 on the ground that retaining this weight throughout makes no allowance for technological changes. The evidence is that such changes have been gradual and there is a presumption that use of the 1959 proportions would, as to this matter, be conservative. The witness adds that operator's costs relate to rotary drilling on-shore only. The evidence is that cable tool and off-shore cost data are lacking through no fault of the compiler. The witness concludes with the objection that four of the component cost series, based on U.S. Bureau of Labor statistics, and two component cost series, compiled by an industry committee, are usable on a nation-wide basis only. This objection has some merit. Interveners' witness excepts, *as to the second index*, on the ground that the contract drilling rate is assumedly a nation-wide index and is therefore not directly applicable to separate states and regions. Interveners' witness excepts, *as to the third index*, repre-

assumption of the applicability of the general index of drilling cost per foot to these particular proceedings concerning the question of conditioning a 1956 price applicable to gas produced from the Louisiana off-shore area.

While the indices constructed by Applicants' witness should not be brushed aside Interveners' basic objection that the indices result from data compiled by various industry associations or related organizations whose methods and techniques have not been subjected to cross-examination cannot be ignored. Only the data which has been submitted pertaining to the changes in average per foot cost of drilling and equipping wells as reported by the U.S. Bureau of the Census and in the Joint Association Survey can be sufficiently related to or checked against official sources to substantially avoid Interveners' objections in this respect.

With respect to the changes in average total costs [111] per foot of drilling and equipping gas and oil wells in all depth categories as reported by the U.S. Bureau of the Census and an industry wide survey [112] it appears that between 1954 [113] and 1956 such costs increased for productive wells in the United States, three Southwestern States, and seven Southwestern States approximately 9% to 12%, and for both Louisiana on-shore and off-shore wells by as much as 34%, while the cost of drilling dry holes increased for all areas in an order ranging from 18.2% for the Louisiana on-shore wells to 37.1% for the three Southwestern States. The increase in cost for both productive wells and dry holes ranged from 12.0% for the United States as a whole to 31.6% for total Louisiana wells.

Tabularly, the results for Louisiana are as follows: [114]

	Cost per foot (dollars)		Increase (percent)
	1954	1956	
Productive wells:			
Offshore	$34.50	$40.42	17.2
Onshore	17.09	21.64	26.6
Total	18.38	24.52	34.0
Dry holes:			
Offshore	38.86	47.55	22.4
Onshore	14.93	17.64	18.2
Total	16.00	21.37	33.6
Total:			
Offshore	35.34	42.89	21.4
Onshore	16.47	19.99	21.4
Total	17.71	23.31	31.6

The difficulty with respect to the acceptance of the foregoing Louisiana statistics is that Applicants' evidence is related principally to average drilling costs for all depths and the record is generally deficient with respect to average costs for wells in depth categories similar to those which obtain with respect to the CATC-Cameron area wells, in that data pertaining to wells drilled to

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senting the combination of a weighting basis of the preceding two, on the ground that the weights used (1954) do not necessarily apply to regions. Both of these objections, as here summarized, have some merit. Exception is finally taken to Applicants' witness' adjustment to the index for changing depth on the ground that average depth data is available only for 3 of the 12 years involved; that data as to the cost per foot within each depth class are available only for 1956.

[111] Not including overhead costs, taxes, insurance, interest, or capital costs.

[112] Joint Survey of Industry Drilling Costs (1955 and 1956) by American Petroleum Institute, Mid-Continent Oil and Gas Association, and Independent Petroleum Association of America.

[113] Data not available of record for all areas for 1952–1953.

[114] Data is available only for the years 1939, 1954, 1955, and 1956, with 1952 and 1953 not being included.

such depths is generally limited to that available for the years 1955–1956. Indeed, in the 1955 and 1956 data there is some indication that changes in costs are greater for those depths which lay outside the Cameron brackets.[115]

On the basis of the foregoing it is concluded that the only reliable indication of the amount of a cost adjustment to be applied to a base price is that afforded in the statistics presented from the Bureau of the Census publications and the Joint Association Survey of Industry Drilling Costs 1955 and 1956. In consideration of this limited data the adjustment cannot very well exceed the least percent of increase which pertains to the Louisiana on-shore and off-shore areas (17.2%, *supra*).

In selecting the base price and applying the correction for increasing costs several matters are involved.

The above mentioned effort of Applicants' to justify the 21.4¢ proposed price in part by reference to a small selection of contemporaneous prices of 20¢, 21.2¢ and 21.4¢ has hereinbefore been rejected, as has Interveners' effort to establish 16¢ per Mcf as the prevailing area price of the pre-CATC period.

Interveners' witness, whose principal interest is in the area of statistical measurement, testified that the unweighted average of South Louisiana new contract prices in 1953–1955 was 14.7¢ per Mcf,[116] but Applicants' witness obtains a corresponding volume-weighted price of 16.9¢ for the same period.[117] and of these two prices that weighted by volume is the more appropriate.

The 17¢ Muskrat Area price offered by Tennessee as a combination price for both the West Delta and the Cameron Areas is not inherently inapplicable to gas produced in the latter, or otherwise it would not only not have been offered by Tennessee as a basis for serious negotiations, but it would not so closely approach the price hereinabove found to have been the best which Applicants could have expected at the time from the alternative intrastate market (18.87¢ less transportation ashore).[118] As the origin of the Muskrat Area price lay in negotiations had in 1954–1955 presumptively those producers would have necessarily anticipated rising costs of drilling. With a continuation of these trends negotiations in 1956 would presumptively and properly have proceeded in the matter of price upon the basis of similar cost considerations. In other words, the permissible adjustment would consist of a translation to the latter date (1956) of an increment equivalent to the estimated actual average increase experienced between the two dates.

On the basis of the foregoing, and the state of the evidence of record, it is concluded that a price of approximately 17¢ effective for the year 1954 is an appropriate base price in the circumstances and that allowance for an in-

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[115] No data is available for the average cost per foot for drilling gas wells since 1954.

[116] He would adjust this price to 16.9¢ as an appropriate 1958 level by applying the relative increase in the trend of drilling costs which he found in the period 1953–1955 to 1958 of 14.3%.

[117] Which he would adjust to a 1958 level of 21.4¢ per Mcf (15.025 psia) by a combination of indices of reserves added per foot and of drilling costs per foot on a 1953–1955 base yielding an increase of 26.6% in drilling costs per Mcf of reserves added. The indices, however, involve resort to Louisiana wide data which relate to wells in depth brackets not the same as those in the off-shore CATC Cameron area. The unexplained indication of a difference in changes of costs related to these respective brackets has already been mentioned above.

[118] The problem is that as only Tennessee and Transcontinental buy off-shore there is no off-shore price pattern. Of 68 Southern Louisiana contracts dated within the period here under consideration (July 1, 1954–June 30, 1956), 17 had an initial base price of 17¢, 25 of 16¢, 14 of prices ranging from 18¢–20¢. The 17¢ contracts yielded 1958 volumes of 91,988 Mmcf (15.025 psia), the 16¢ contracts 61,305 Mmcf, the 18¢–20¢ contracts a combined total of 73,074 Mmcf (15.025 psia). No other price appears to bear as direct relation to the Cameron Area, geographically, as does that of the Muskrat Area.

crease in costs between that year and 1956 of 17.2%, or 2.92¢ per Mcf, which is likewise appropriate and that the resulting price of 19.92¢ per Mcf (15.025 psia),[119] is acceptable for the purposes of the case.

The correlation of drilling costs and gas reserves added, which represents a step in Applicants' witness' general cost index procedure, is not possible on this record with respect to Applicants' overall Louisiana operations. The possibility that such a consideration would be relevant is somewhat indicated by the fact that in the Cameron Area the CATC reserves represent approximately 3,333.3 Mbtu per foot drilled, including producers and dry holes, an apparently not unfavorable showing.

In the absence of some correlation of the productivity of drilling results and drilling and operating costs Applicants' evidence to the effect that 66.3¢ of the total costs of CATC-Cameron Area off-shore productive wells represents costs peculiar to off-shore operations, that Louisiana off-shore drilling costs are more than twice those onshore, and actual Cameron offshore operating costs are more than three times those of the Applicants' onshore operating costs, can be given only that effect in this decision which the foregoing use of drilling cost indices provides.

Custom as to Pipeline Connections

It is a common practice, where gas reserves are sufficiently attractive, for the pipeline to build and own the line connecting the gas producing field to the main line system, particularly in new areas where the pipeline purchaser desires to be in a favorable position to purchase reserves subsequently developed. Accordingly, during negotiations construction of a pipeline was not discussed as it was assumed by both Applicants and Tennessee that the latter would construct and own the connecting line,[120] and, further, in relation to the so-called "favorable position," Tennessee has since executed further contracts with Shell Oil Company and the so-called Magnolia, Continental and Newmont (MCN) group in the Cameron area which commit to it substantial reserves,[121] and, is anticipating the delivery to the line of even additional volumes.

It has been Tennessee's custom over a long period of time to build at its own expense without monetary contribution by others [122] both short and main laterals from its main transmission lines in the Gulf Coast area to its various sources of supply, among which are the principal laterals to: Sullivan City and Tobasco fields in Hidalgo County, Texas;[123] fields in Duval and McMullen Counties,

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[119] Before taxes or consideration of transportation costs. Weighting the 1954–1956 increase in drilling cost of 17.2% for off-shore productive wells by the number of Cameron productive wells (26) and the increase in such costs of 22.4% for off-shore dry-holes by the number of Cameron off-short dry holes (13) would yield a result of 20.2¢ per Mcf as the adjusted price. However, this refinement should have had, but does not, the support of expert testimony. The evidence permits no weighing of the less significant effect of relative levels of production operating expense.

[120] In all approximately 46 miles of 26-inch line on shore, and 25 miles of 26-inch, 11 miles of 20-inch, 13 miles of 16-inch, and 11 miles of 12-inch main and lateral line offshore. At least five of the leading offers received by the CATC companies for the Cameron gas proposed taking the gas either at a central point in each field or at the platform. Of course, the nearer the gas to established facilities the more valuable it is to the pipeline.

[121] On the basis of an average day Tennessee expects in 1960 to receive 205,400 Mcf of gas from the three sources (CATC, MCN, and Shell), this amount rising in 1963 to 258,000 Mcf (14.73 psia). The volume of the deliveries from CATC, Shell, and MCN, severally, are not available, but the relative recoverable reserves as of January 1, 1958, give an indication of the relative order of magnitude of such deliveries, and, according to a statement of record by Tennessee's counsel, were: CATC, 1,322,921 Mmcf; MCN, 498,051 Mmcf; and Shell, 330,921 Mmcf.

[122] With those several exceptions which pertain only to small 2, 4, or 6-inch lines, including the line to the Zim-Rickaby field, Starr County, Texas.

[123] Built in 1956, 40 miles in length, 8 and 12 inches in diameter.

Texas;[124] Mustang Island and Corpus Christi Bay fields, San Patricio County area, Texas;[125] East Bay City and Lucky fields, Matagorda County, Texas;[126] Carthage field, Panola County, Texas;[127] and Bayou Sale field, St. Mary Parish, Louisiana.[128] It also built the so-called Muskrat line as an extension from the Bayou Sale field to various South Louisiana fields in the South Pastor delta area, for the same purposes.[129]

Insofar as the practice is recognized in the operations of the Applicants it is disclosed that Cities and its affiliate, Cities Service Oil Company, made all 1959 interstate and intrastate deliveries of dry, condensate, casinghead, and residue gas of 231,357,947 Mcf (14.65 psia at the well, a central point in the field, or the tailgate of the processing (gasoline) plant located in or near the field)[130] and that Tidewater and Atlantic did the same with respect to their jurisdictional and non-jurisdictional current sales.

In the same supply area other pipelines, including Transcontinental Gas Pipe Line Corporation (Transco), Trunkline Gas Company, Texas-Illinois Natural Gas Pipeline Company, and United Gas Pipe Line Company, among others, have constructed similar lines in the Texas and Louisiana Gulf Coast areas to pick up gas from various fields with which they connect.

The Kinder line extensions to the Cameron area appears to be of the same general nature as the extensions cited, and, accordingly, insofar as a comparison of the Muskrat Area operations and price is involved in the testing of the Cameron Area price the cost of transportation need not be considered *per se* as a discriminatory factor. The magnitude of the cost of transportation on the Kinder-CATC line as computed by Staff is considered in a following section of this decision.

Transportation of Distillate

In its initial proposals Tennessee offered to transport the distillate produced with the gas from the offshore properties without cost to the producers. It has installed no facilities for the specific purpose of handling the distillates and, therefore, the cost of its line from Kinder, Louisiana, to the platforms would have been no less even had it assumed no transportation obligation.

The condensate liquids, or distillates, are separated from the gas at the platform where the latter is also dehydrated to 7 pounds of water per 1,000 Mcf. These steps facilitate measurement of the gas by the operator (Continental) for the purpose of determining the production taken from each lease as well as the related working interest and royalty rights with respect thereto, and also facilitate the efficient operation of both wells and pipeline.

After measurement the condensate liquids and gas are recombined and delivered to Tennessee which then transports the composite to shore where the

[124] Built before 1957, in various sections and at various times, in all about 70–80 miles in length.

[125] Built in 1951, 32 miles in length, 12 inches in diameter.

[126] Built in 1949, some 40–50 miles in length, probably 12 inches in diameter.

[127] Built in 1948, 72 miles in length, 20 inches in diameter.

[128] Built about 1951 via Midland and South Tigre Lagoon fields, 130 miles of pipe, 16 inches in diameter.

[129] Built in 1956, 85 miles of 24-inch diameter plus 32 miles of 20-inch diameter line, and considerable other lengths of various smaller sizes of pipe. Whether looping of the Bayou Sale line is here included is not clear. The line was constructed by Tennessee in order to serve the fields in a five-parish area. Laterals located more or less at the southeastern extremity reach, respectively, to Dixon Bay, South Pass, and Main Pass to connect with the CATC and Shell acreages. Other principal laterals also extend from mid-sections of the line to connect with the Mayfield acreage, principally in Assumption Parish, and California acreage in La Fourche and Jefferson Parishes, and again in Plaquemines Parish.

[130] The sales contracts which require the purchaser pipeline company or gatherer to build facilities connecting the field go back as far as 1927.

gas is processed in Applicant's Grand Chenier separation station for final removal of condensate liquids and dehydration, and for the limited recovery of liquefiable hydrocarbons. After these steps the gas is remeasured and redelivered to Tennessee.[131]

The alternative transportation of liquids by barge would result in loading operations which with sea and weather could interrupt the delivery of gas to Tennessee by as much as 14% of the time.[132]

The ratio of condensate to gas in the Cameron area is exceptionally low, averaging during 1959 some 7.9 barrels per 1,000 Mcf,[133] and, accordingly, on the assumption that the line is consistently operated at capacity so that liquids would occupy space otherwise usable for the transportation of gas, Tennessee computes the maximum cost of transporting both distillates and liquefiable hydrocarbons to be about 0.0148¢ per Mcf of gas delivered.[134] However, on the possibility that additional gas purchased by Tennessee may have the same degree of wetness and, accordingly, on the premise that line capacity would be shared on a pro rata basis this cost would then increase to some 0.044¢ per Mcf.[135]

This aspect of the CATC-Tennessee Cameron Area transaction is of no substantial effect.

Staff Transportation Costs Computations

Staff tendered a witness who testified, in effect, that with offshore annual volumes of 60 million Mcf (15.025 psia) 4¢ per Mcf would a reasonable estimate of the cost incurred by Tennessee in gathering and transporting the CATC gas from point of purchase at the offshore platform to Tennessee's main line station (No. 823) at Kinder, Louisiana.[136]

The CATC facilities lie in what is known as Tennessee's Kinder, (La.) operating district.[137] As Continental, for bookkeeping purposes, commingles CATC facility operating expenses with those related to other district pipelines Staff obtains its CATC direct operating costs on an incremental basis involving the month by month deduction of prior expenses from those of the 12 months ended

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[131] Applicants are charged with losses in volume in the processing and dehydration which takes place ashore. It is not feasible to construct a gasoline plant for processing the gas at the platform location.

[132] Also in barging some 0.85% of the gas escaping as solution gas when pressure on the condensate is released would be flashed and lost beyond recovery.

[133] As compared with 60–65 barrels in the gas produced in the West Delta area. In addition the Cameron gas contains 5.6 barrels of liquefiable hydrocarbons per 1,000 Mcf with 30% propane recovery; the West Delta gas containing 15 barrels of natural gas liquids with the same propane recovery.

[134] As to condensate liquids; assuming CATC deliveries of 240,000 Mcf per day (14.73 psia) with 8 barrels of distillate per Mcf occupying 5.61 cubic feet per barrel, a daily maximum powered line capacity of 424,000 Mcf, and maximum line operating pressure of 1000 psig. As to liquefiable hydrocarbons: assuming in addition a shrinkage of 1.6% of the volume of gas processed. To get annual operating costs Tennessee applies a factor of 17% to its pipeline cost of approximately $12,000,000 (sic).

[135] It may be observed that Tennessee's pre-CATC contract pertaining to the purchase of gas in the Corpus Christi Bay and Mustang Island fields carried a provision reserving to the producers the right to extract liquid hydrocarbons after delivery and transportation ashore. It also appears that Cities and others have several contracts of various dates, operative in other areas which permit the producer to process gas on the main pipeline, after the pipeline has carried without charges the gas laden with the liquefiable hydrocarbons to the processing plant site.

[136] Compared with a similarly computed cost of 5½¢ per Mcf for the preceding 12 months ended June 30, 1959, when the total volume was 43,004,062 Mcf (15.025 psia).

[137] According to Staff witness the Kinder district is a supply district with feeder lines only. The CATC facilities embrace some 108.96 miles of line extending 71.66 miles from Kinder to a central offshore point and thence to platforms. The section which constitutes the onshore portion is 46.36 miles in length while the remaining 25.30 miles to the field point is all offshore.

June 30, 1960, and the pro rating of these results in the ratio of gross CATC facility mileage to gross district feeder pipeline mileage including that of the CATC facilities.[138]

Direct costs thus computed by Staff on an incremental basis for the 12 months ended June 30, 1960, are:

Operating:		
Supervisory labor	$2,994	
Supervisory-other	3,994	
Employee expense	1,426	
Other direct costs	6,293	
Total operating costs		$14,707
Maintenance:		
Supervision	$951	
Field lines	6,009	
Other	7,903	
Total maintenance costs		14,863
Total direct costs		29,570

To the foregoing incremental direct costs Staff adds $12,851 of administrative and general costs computed at the company-wide rate of 43.46¢ per dollar of direct (supervised) costs, to obtain total operating expenses of $42,421.

The administrative and general expense ratio ($43.46¢) derives from studies made by Staff in the Tennessee rate proceeding (Docket No. G–19983) involving a 12-month test period ended July 31, 1959.[139] The just criticism of this method is that it assumes that administrative and general expense for a gathering facility is at a common level with those for all the other varied facilities and functions of a large pipeline system as comprehensive in nature as Tennessee's,[140] with no evidence of the nature of the supervision which the CATC or similar facilities must necessarily receive.[141] In the absence of some such showing so-called costs determined by the employment of a ratio are not useful in this proceeding.

[138] The witness testified to the effect that an attempt to precisely segregate costs from commingled book figures would be impracticable. As of June 30, 1958, there were 349.19 miles of pipeline of all sizes in the district, to which were subsequently added the 108.96 miles of CATC facilities. The witness' method does not take into account pipe sizes although size has a bearing on cost. Allocation of test period total costs on the basis of a simple ratio of pipeline mileage would have imposed a lesser ultimate cost on the CATC facilities.

[139] This ratio involves some adjustments to book expenses both in administrative and general and in supervised expenses, which the witness states are minor in character. Staff witness testified to the effect that this ratio has been a stable one as far back as 1951. For the year ended July 31, 1959, unadjusted company-wide administrative and general expenses per books ($8,691,625) constituted some 42.48¢ per dollar of total supervised expenses per book which related to natural gas production and gathering ($1,949,641), production extraction ($1,226,503), exploration ($1,736,085), other gas supply expense ($320,637), underground storage expense ($273,239), transmission expense including compressor station operation and maintenance ($14,241,696), and distribution expense ($714,507), for a total of $20,462,308.

[140] See the preceding footnote. Tennessee has no compression on the CATC line.

[141] Passing reference in Counsel's cross-examination to the allocation of administrative and general expense by Tennessee to construction (capitalizing) as well as operations is inconclusive as suggesting a contradiction of Staff's witness' procedures. Also the latter's opinion that it is not possible to make a study which would lead to a direct determination of the cost of supervision is likewise inconclusive.

Staff computes from work orders an average net plant for the year ended June 30, 1960, of $19,462,272, after a so-called normalization of gross investment as of the commencement of the period.[142]

Depreciation is taken at a composite annual rate of 3.25%, on the basis of testimony in the Tennessee rate case (Docket No. G–19983) in Staff's behalf which the witness in this proceeding, however, could not directly support as applicable to the CATC facilities. Nevertheless, the rate so proposed is less than the composite 3.5% rate which has been used by Tennessee since July 1, 1957, as applicable to all of its facilities, and it may be assumed that offshore conditions would more probably require the application of a higher rate than a lower one. In any event, this is a matter which Applicants could have easily rebutted if prejudiced thereby. On this basis the annual depreciation expense for the test period computes to $664,547.

Return ($1,192,064) is computed at the 6.125% rate prescribed by Commission's order issued August 9, 1960, in the Tennessee rate proceeding (Docket No. G–19983, *supra*) in which Tennessee claimed a 7% rate as a proper allowance. Staff's use of a 6.125% rate is appropriate in the circumstances.

The Federal income tax allowance ($278,439) is determined by the witness by the use of a ratio computed by Staff in the aforesaid Tennessee rate proceeding, in which income tax losses arising from Tennessee's non-utility and foreign operations were utilized to effect reductions in utility net taxable income and yield an income tax ratio of 23.3577% of return, as compared with a ratio of 44.2739% without the reductions. The merit of the ratio is not here at issue, it being sufficient to observe that as used by the Staff for the purposes of these proceedings it is the lower of the ratios available, the book ratio or the amount claimed by Tennessee in its rate proceeding (Docket No. G–19983) which is on review also being, in effect, higher.

The determination of the allowance for State income taxes ($15,568) is based upon a composite ratio (1.306%) also determined in the aforesaid Tennessee rate proceeding which is derived by dividing Staff's allowance for total state income taxes for several states ($654,129)[143] by the total return, without giving effect to consolidation or the offsetting of nonutility losses. No reason is given for using other than the Louisiana tax and the ratio of the latter is not here available.[144] Therefore, the computation here used by the Staff is not appropriate.

The Louisiana ad valorem tax allowance ($172,545) is based on the 1959 composite State rate and is improperly spread to all of Tennessee's CATC facilities extending from Kinder out to, and beyond, the offshore field central point, or, apparently, in substantial part beyond the jurisdiction of the State.[145]

On the basis of the foregoing, and the premises adopted by the Staff, costs acceptable for the purposes of tentatively appraising the proposed price for gas in the light of CATC transmission costs to Tennessee are:

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[142] By adding an estimated $3,000,000 to some $17,000,000 of actual facility cost. The reasoning is not explained, but in any event is said not to affect the 1959–1960 test year results.

[143] Arkansas, Kentucky, Louisana, Mississippi, New Jersey, and Pennsylvania. The assumedly composite per book figure is somewhat lower ($566,760).

[144] Further, the basis upon which Louisana might validly apply the tax to Tennessee's CATC offshore operations is not stated.

[145] Kinder, it will be recalled, is approximately 46.36 miles in from the Louisana shore while the platforms are approximately 25.3 miles or more offshore. However, the location of the shore-line is involved in the offshore title dispute between the State and the Federal Government.

Direct costs	$29,570
Depreciation	664,547
Return	1,192,064
Federal income tax	278,439
Total	2,164,620

Staff witness uses a volume of 58,769,006 Mcf (15.025 psia) to obtain the unit cost of 4¢ per Mcf for the test twelve months ended June 30, 1960, but concedes that generally the facility costs are very largely fixed costs and will decline unit-wise with increases in the volumes of gas transported.

The main portion of the CATC facilities are designed to transport, when powered, some 416,000 Mcf per day (15.025 psia) and even before that event to provide additional capacity to enable Tennessee to transport substantial additional quantities of gas which it might acquire from others in adjacent offshore areas. Indeed, of 58,769,006 Mcf transported by Tennessee during the test period ended June 30, 1960, a total of 11,599,176 Mcf (15.025 psia) represented offshore purchases by Tennessee from the Shell Oil Company.

Staff witness was not informed as to the certificated capacity of the CATC line, did not know what portion of the capacity is now used to transport the CATC gas, and made no studies to determine whether the facilities would be called upon in future periods to transport additional volumes before or after the installation of additional facilities,[146] although it appears in Docket No. G–14562 (1958) that Tennessee has already considered this matter and has since (1960) proposed in the same docket to transport through these CATC facilities production from some 341,557 MMcf (15.025) of reserves acquired by it in offshore Block 64.[147]

The CATC volumes are even now increasing,[148] and totals for Applicants, Shell Oil Company, and the so-called MCN leases are expected to average 252,934 Mcf (15.025) per day by 1963 and again by 1967. Indeed, in May 1960 the facilities were taking as much as 176,000 Mcf per day of CATC gas and in June 1960 some 127,000 Mcf. For 1960 Tennessee estimates a total of 201,400 Mcf per day from the CATC, Shell and MCN combined sources.[149] Use of this latter volume would yield an indicated cost of 2.94¢ per Mcf, or adding in a normalized rate of production from Tennessee's own reserves, an indicated cost of 2.39¢ per Mcf, or with the 1963 expected CATC, Shell and MCN volumes, plus Tennessee's normalized production, an indicated cost of 1.98¢ per Mcf which is generally consistent with the findings in this decision pertaining to the Cameron Area reserves.

Gas flows into Kinder from other fields in Texas and Louisiana, some from as far as the Rio Grande valley (Texas), 400 to 450 miles distant. Staff witness made no determination of the gathering and transportation costs incurred by

[146] As a related matter, the witness did not consider the existence or nonexistence of potential reserves adjacent to Tennessee's CATC line.

[147] This would mean an average of 17,077,850 Mcf per year over an assumed 20 year life.

[148] Thus, from Exh. 38 and the latest figures available (15.025 psia):

	1958 (Mcf)	1959 (Mcf)	1960 (Mcf)
July	531,419	3,715,836	4,766,938
August	2,450,000	3,544,342	5,267,833
September	3,047,589	4,067,575	5,365,193
October	4,167,786	2,786,699	5,618,838

[149] On an assumed 15.025 psia basis.

Tennesssee with respect to such other gas and was not able to state whether at Kinder the cost of purchasing, gathering, and transporting the CATC gas was more, less, or the same, as that for gas obtained by Tennessee from other fields. Interveners, also, were content to rest in this respect upon the general state of the evidence of record.

The evidence would not support the use of a higher cost for gathering and transporting CATC gas than the 1.98¢ per Mcf above obtained. Moreover, in connection with the resort to the so-called Muskrat Area rate above, and with respect to the extensive facilities owned and operated by Tennessee to transport the Muskrat Area gas to its main-line transmission facilities, it would clearly appear that grounds do not exist that would justify giving effect to the computed transportation figure of 1.98¢ per Mcf, in determining a reasonable price in this this proceeding.

Cost of Service—Continental's Cost Results

Continental's position is that it is impossible to determine the actual separate cost of liquids and gas produced as joint products, that actual costs could not be available for use in the usual certificate case, and further that if costs are to be used, a company-wide basis of cost determination would be a necessity.

Specifically, applicants' witness, Continental's vice president in charge of finance,[150] testified to the effect that at the certificate stage, a cost of service study for a specific gas property would not provide a reliable basis upon which to determine whether the price for gas was, or was not, consistent with the public interest, assertedly because, in particular: direct operating expense experience would not be available, and the allocation of joint costs and, also the calculation of depletion and amortization expenses would have to be made on the basis of initial reserve estimates of an inherently tentative nature.[151]

This witness also testified that the best cost of service determinations for specific properties in the same supply area would be subject to such wide dispersions [152] that the direct application of such results would serve to disrupt the area price structure. He further testified that "guaranteeing" the recovery of costs would eventually serve to increase the cost of gas to interstate users as against the cost of gas to intrastate users.

However, Continental's cost of service witness prepared a test year (1959) computation in which he arrives at 43.69¢ per Mcf as the isolated cost of gas delivered by Continental to Tennessee from the CATC Cameron offshore leases.[153]

While direct production operating costs related to the Cameron area leases are shared equally by each of the Applicants, exploration costs are computed by each Applicant separately.

A simplified comparison of production costs associated with Cameron gas-only leases and the gas portion of the combination leases, which omits the relatively minor allocated special facility costs, discloses a gas-only production cost of service of 40.30¢ per Mcf and a condensate gas cost of service of 24.73¢ per

[150] Officially, Vice President, Finance and Transportation.

[151] In the Cameron area 23 of the CATC wells produce condensate along with natural gas.

[152] In the normal course of bargaining small supplies usually bring prices lower than those for large supplies, though having the higher associated unit cost.

[153] Including also Continental's interest in the MCN portion of the CATC–MCN Cameron offshore unit in computing the amortization of intangible drilling cost, but the effect of omitting or including this unit is relatively insignificant. Continental's test year (1959) production from the Cameron leases is some 10,014,362 Mcf (15.025 psia). No part of regulatory commission expense, which is presently estimated to be $495,548 for the whole case, is included in the cost of service.

Mcf, each of which is, in general, significantly larger than the price proposed in these proceedings (21.4¢/Mcf).[154]

Continental's production department net investment applicable to the Cameron leases includes in part lease and well equipment ($1,164,600), intangible drilling cost ($3,722,625), producing leaseholds ($137,614), and allocated general investment ($175,414).[155] The investment also includes an allocation ($141,816) of the CATC region drill tools investment ($1,162,427) effected on the basis of the number of CATC Cameron wells drilled to the total CATC oil and gas wells drilled in the region,[156] plus investment in certain special facilities ($88,215) charged entirely to gas, for an area total investment of $5,430,284.

After allocation production department total gas net investment in Cameron leases, direct and allocated becomes:[157]

Lease and well equipment	$1,122,277
Intangible drilling costs	3,577,583
Producing leaseholds	131,629
General investment [1]	168,983
Total	5,000,472
Drill tools and facilities [2]	221,481
Cameron area production investment	5,221,953

[1] Production department general investment and general company investment as allocated.

[2] Correcting to allocate a portion of special facilities to liquids.

Cameron area production expense includes the direct and indirect operating expense ($264,082), depletion ($5,574), depreciation ($109,247), and amortiza-

[154] No particularly significant allocation problems are involved with respect to most production costs, as the general investment and overhead expense items are less than 4.5% of the respective totals. Depletion is an insignificant item of expense and depreciation is generally in accord with established company rates. However, amortization of intangible drilling costs of $412,749, out of a total of $499,501 of production expenses, involves the write-off in 1959 of the remaining investment in two abandoned wells: $262,119 and $100,118 respectively, for a total of $362,237.

[155] General company investment allocated to the production department ($9,950,899) on the basis of gross direct department assets and the production department's own net general investment ($9,389,083), are allocated to the Cameron leases on the basis of direct lease operating expense, $90,255 and $85,159, respectively. The ultimate allocation to condensate gas utilizes the Btu equivalent of 1959 production of condensate gas (8,267,685 Mcf at 1,097,400 Btu per Mcf) and the Btu equivalent of production of lease liquids (78,058 barrels at 5,400,000 Btu per barrel).

[156] The total, inconsistently including that part of the drill tool investment which is, in effect, allocated to dry gas leases on a per well basis, is allocated to gas on the basis of the Btu equivalent of 1959 production of Cameron gas from both gas and combination leases (10,014,362 Mcf at 1,056,000 Btu per Mcf for the dry gas and 1,097,400 Btu per Mcf for the wet gas) and the 1959 production of Cameron liquids from the combination leases (78,058 barrels at 5,400,000 Btu per barrel).

[157] Excepting drill tools and special facilities the amounts allocated compare as follows:

	Gas only	Gas allocated	Total
Lease and well equipment	$211,385	$910,892	$1,122,277
Intangible drilling costs	455,917	3,121,666	3,577,583
Producing leaseholds	2,821	128,808	131,629
General investment	30,578	138,405	168,983
Total	700,701	4,299,771	5,000,472

tion ($741,641), and production department and general company overheads ($127,178), of which all but the overheads can be related to the lease.[158]

Combination lease expenses ($740,530) are allocated 95.56% to gas ($707,651) on the basis of the Btu equivalent of gas and liquid production in the 1959 test year. The Cameron area production total of gas-only and allocated gas expenses thus becomes:[159]

Operating expense	$254,280
Indirect expense	120
Depletion	5,332
Depreciation	97,882
Amortization	727,022
Overhead-allocated [1]	122,516
Total	1,207,152

[1] Allocated to leases on basis of direct lease operating expenses and to gas on combination leases on basis of Btu equivalent of 1959 production of liquids and gas.

To the foregoing there is added special facilities depreciation and amortization expense ($7,406)[160] and allocated production taxes associated with special facilities ($30,059) for a total of Cameron area gas production expense of $1,244,617.

Adding a 14% return ($731,073) on Cameron area gas production net investment ($5,221,953) and the tax allowance ($791,996 at 108.3333% of return) Continental's method yields a Cameron area gas production cost of service of $2,767,686 or 27.64¢ per Mcf.[161]

Continental uses five year (1955–1959) averages to even out general fluctuations in the costs of exploration.

[158] Overheads do not include FPC regulatory expense. Company general and administration expense ($12,618,166) is allocated to the production department ($8,506,663) on the basis of department direct gross operating assets (67.416%); the production department and allocated company general overheads ($5,515,216 and $8,506,663, respectively), are then allocated to the Cameron area gas-only and combination leases on the basis of lease operating expense (90.7%).

[159] Omitting the relatively minor special facility expense the amounts allocated compare as follows:

	Gas only	Gas allocated	Total
Operating expense	$46,013	$208,267	$254,280
Indirect expense	19	101	120
Depletion	114	5,218	5,332
Depreciation	18,436	79,446	97,882
Amortization	412,749	314,273	727,022
Overheads	22,170	100,346	122,516
Total	499,501	707,651	1,207,152

[160] That is, depreciation $7,389 and amortization $17, as corrected to allocate a portion to combination lease liquids.

[161] Using test year production of 10,014,362 Mcf from the Cameron area gas-only and combination leases.

Continental derives its exploration department net investment as follows:

	Five year total	*Five year average*
Exploratory authorizations	$13,802,127	$2,760,426
Non-producing leaseholds	256,278,955	51,255,791
Core-drill investment	224,940	44,988
Geological investment	94,601	18,920
Geophysical investment	2,361,849	472,370
Land department field equipment	32,055	6,411
Exploration department authorizations	1,238,001	247,600
Total	274,032,528	54,806,506

Applicant's general investment allocated to exploration on the basis of direct departmental assets (5.603%) amounts to $827,027 of a total of $14,760,441 of company-wide general net investment.

Continental computes company-wide exploration department expense also on the basis of 1955–1959 five year averages as follows:

	Five year total	*Five year averages*
Depreciation expense	$1,447,718	$289,544
Dry hole costs	63,197,535	12,639,507
Department expense	37,497,110	7,499,422
Dry hole payments	2,738,311	547,622
Lease rentals	23,338,689	4,667,738
Social security, etc., taxes	901,062	180,212
Geophysical operations	31,334,500	6,266,900
Core drill operations	1,549,106	309,821
Leaseholds sold	(176,096)	(35,219)
Surrendered leases	40,279,216	8,055,843
Total	202,107,151	40,421,430

Continental's general and administrative expense allocated to the exploration department on the basis of direct gross operating assets (5.603%) totals $706,996 of a company-wide total of $12,618,166.

A 14% return ($7,788,695) on the exploration department total net investment ($55,633,533, above) and tax allowance ($8,437,750 at 108.333% of return) added to the foregoing total of exploration department expense ($41,128,426) results in a total cost of service for exploration of $57,354,871 of which $21,946,841 (38.265%) is allocated to gas on the basis of the company-wide five-year (1955–1959) average production of liquids and gas expressed in terms of Btu equivalents, for an average company-wide exploration unit cost of service of 16.03¢ per Mcf,[162] or, applying to the Cameron area test year (1959) production of 10,014,362 Mcf (15.025 psia), a Cameron area exploration cost of service of $1,605,302.

Continental's Cameron cost of service, not including regulatory expense,[163] thus totals:

[162] The 38.265% company-wide allocation of expenses, return and taxes to gas rests on the conversion of the five-year (1955–1959) average of annual production of liquids (48,943,454 bb.) and gas (136,950,646 Mcf, 15.025 psia) to Btu equivalents at the rate of 5,880,000 Btu per barrel and 1,302,500 Btu per Mcf.

[163] As of April 30, 1960—$495,548.

	Total costs	*Production* (Mcf)	*Unit cost* (¢/Mcf)
Production department	$2, 767, 686	10, 014, 362	27. 64
Exploration department	1, 605, 302	10, 014, 362	16. 03
Total	4, 372, 988		43. 67

Interveners' Cost Results

Interveners use Continental's Cameron area on-lease production expenses, adjusting Continental's $362,237 write-off of two leases in the gas-only category [164] so as to provide for a substantial capitalization and an amortization thereof effectively at the rate (9% appr.) at which Interveners amortize allocated intangible drilling costs.[165] Continental's on-lease expenses of the combination leases are allocated to gas (78.26%) on a so-called imputed cost basis by taking a ratio of Continental's 1957 company-wide gas-only on-lease costs of 3.03¢ per Mcf [166] applied to its 1959 Cameron area condensate gas production (total $250,511) and Continental's 1957 company-wide oil-only on-lease costs of 89.14¢ per barrel [167] applied to Continental's condensate production from the Cameron area combination leases (total $69,581). The allocation of combination lease expenses to condensate gas ($49,277), plus the adjusted on-lease expense for the four gas-only leases ($160,951), results in a 1959 allocated production expense of $658,228—before indirect expense, overhead, production taxes, and regulatory expense, or, unit-wise some 6.57¢ per Mcf on the basis of Continental's 1959 Cameron area production of 10,014,362 Mcf of dry and condensate gas.

Interveners also use Continental's Cameron area production net direct investment, adjusting in the instance of gas-only leases to add the portion of the two 1959 write-offs capitalized ($316,351),[168] and allocate the on-lease net investment for the combination leases ($4,354,716) to gas by use of a relative investment cost factor (87.68%) based on Continental's on-lease company-wide

[164] Continental's expenses plus the write-off adjustment as indicated are:

	Gas-only leases	Combination leases
Operating expense	$46, 013	$217, 944
Depletion	114	5, 490
Depreciation	18, 436	83, 137
Amortization (gas-only, adjusted)	96, 388	328, 875
	160, 951	635, 416

[165] Also substantially the average rate obtained from book figures appearing in Staff's Exh. 37, Sched. 5. The mathematics of the determination of the total gas-only amortization of $96,388, contained in work papers which are not in evidence, is only partly explained by reference to the 9% rate which Interveners here employ.

[166] Involving 1957 operating expenses, depletion, depreciation and amortization related to some 180 gas-only leases.

[167] Involving aggregate expenses on some 760 oil-only leases which are pumping.

[168] Thus—

	Gas-only leases	*Combination leases*
Lease and well equipment	$211, 385	$953, 215
Intangible drilling cost	455, 917	3, 266, 708
Producing leaseholds	2, 821	134, 793
Total direct investment	670, 123	4, 354, 716
Adjustment (write-off capitalized)	316, 351	
Total adjusted investment	986, 474	

gas-only unit investment (16.77¢ per Mcf) applied to Continental's 1959 Cameron area condensate gas production (8,267,685 Mcf) and Continental's on-lease company-wide oil-only investment ($.496 per bb.) applied to Continental's 1959 Cameron area liquid production (78,058 bb.). The resulting allocation of combination lease investment to condensate gas ($3,818,215), plus the on-lease net investment in gas-only leases ($986,474), represents an assignment of investment to gas equal to 89.96% of the total direct net investment in all Cameron area leases, which ratio applied to the Cameron area indirect net investment ($322,538)[169] further allocates as gas investment $290,155. Gas production net investment, including general investment, thus becomes $5,094,844.

Interveners accept Continental's 1957 book exploration department expense of $45,180,462 of which $4,915,634, or 10.88%, is allocated to gas on the basis of the so-called reserve-added-realization method,[170] however, without provision for administrative and general expense. Using 1957 gas production of 133,037,858 Mcf, including that from the since sold Rayne Field, Interveners obtain a unit exploration expense of 3.69¢ per Mcf. The Interveners also accept, in effect, Continental's 1957 company-wide exploration department year-end net investment of $55,939,725, of which they allocate, according to this same method, $6,086,242, or 10.88%, to Cameron area gas without provision for general company investment, working capital or tax benefits.

Interveners determine the reserves-added-realization ratio (10.88%) as the value of gas reserves retained from among those added by Continental during the five-year period 1953–1957 to the total value of gas and oil reserves added, eliminating from reserves retained, but not from reserves added, Continental's so-called Rayne Field reserves which were discovered about 1953 and sold in 1958.

To obtain the value of Continental's gas reserves added in the period 1953–1957, as well as the value of the Rayne reserves sold, Interveners use the average price of 15.31¢ per Mcf for gas delivered in 1958 under contracts executed in 1957 by a group of 27 interstate pipeline companies, escalated at 1¢ per Mcf each 4 years and discounted, at the assumed rate of return of 11% over an assumed life of 20 years, to 6.58¢ per Mcf. To obtain the value of Continental's liquid reserves added in the same period Interveners use Continental's 1957 average liquids price of $2.97 per barrel, discounted at the assumed rate of return of 11% over an assumed life of 10 years, to $1.75.

Corresponding ratios are not available for other Applicants, but the proposed discount of the average liquids price over 10 years cannot be applied to allocate costs between Cameron area gas and condensate where according to the evidence only 54.2% of the condensate will have been produced by the end of the first 10 years (1969).[171]

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[169] The Cameron area indirect net investment, allocated per Staff, consists of:

Drill tools	$110,547
General investment:	
Production department	60,090
General company	63,686
Special facilities	88,215
Total	322,538

[170] Interveners' allocation witness was of the opinion that this method would allocate to gas a share of expenses equivalent to the general role that the prospect of finding gas played in motivating the joint outlay in the test year. He conceded, however, that in general exploration cannot be successfully directed as between oil or liquids and gas.

[171] There is no fixed relation between life indices and the time required to produce particularly a reserve of oil—the rate of depletion of a gas field changes very little over the productive life of a field but generally oil fields have a long period of reduced production before abandonment.

There is a further basic objection to the acceptance of the reserves-added realization method of allocation as here proposed for this method would ascertain costs for the purpose of regulating price by reference to that very price, and again, without any further justification, a change in the price of either oil or gas would effect a shift in costs between them.

Staff's Cost Results

Staff uses operator's (Continental) cost data,[172] and employs the same test year for determining the Cameron area cost of production (1959), and the same five-year averages for determining the cost of exploration (1955–1959), as do Applicants.

With an "illustrative" 9% return, actual income taxes and allocations, Staff calculated unit costs of production and exploration, adjusted, compare with Continental's corresponding costs (*supra*) as follows:

	Staff (¢/*Mcf*)	*Continental* (¢/*Mcf*)
Production unit cost	12.77	27.64
Exploration unit cost	4.56	16.03
Total unit cost	17.33	43.67

Continental's Cameron area lease, special facility, department drill tool and general investments are accepted by Staff, but where Continental uses a Btu method to allocate joint on-lease investment in combination leases to condensate gas Staff uses a gross revenue basis of allocation, which reflects a price for liquids of $3.21 per bb. and a price for gas which is substantially the 21.4¢ per Mcf here proposed.

Compared with Continental's use of number of wells and Btu's of production to allocate the CATC region drill tool investment, first to the Cameron area and then to gas, Staff uses a gross investment, and a gross revenue basis, respectively, with prices as above. Finally, where Continental allocates general investment by a combination of gross investment, lease operating expenses, and the Btu of production. Staff uses a combination of two stages of gross investment to department and to lease, and gross revenues to gas.[172a]

Staff's Cameron area gas production investment, including direct investment, drill tools, special facilities, and general investment, thus amounts to $4,781,635 as compared with Continental's corresponding $5,221,953 (*supra*).[173]

The differences in the foregoing results are attributable, substantially, to Continental's Btu and Staff's gross revenue basis of allocation. Continental's Btu method has the inherent objection indicated in a following portion of this decision, while Staff's involves technically an unwarranted assumption as to the validity of a price, despite the fact that the price is the very matter at issue.

Staff accepts Continental's production book operating retirement, depletion, depreciation, overhead and production tax expense for both the Cameron area and gas-only leases.[174] The principal difference between Staff and Applicant here relate to the amortization associated with Staff's treatment of investment

[172] To avoid differences in accounting methods of the several CATC Applicants, Staff, assumes as do Applicants, that the production costs for the other three would be reasonably close to Continental's cost of service.

[172a] No basis is shown for allocating production department general expense to the Cameron area on the basis of an investment ratio which excludes investment in intangible drilling costs and which has in the denominator "other" company investment.

[173] Correcting both Staff and Continental in the minor matter of allocation of special facilities.

[174] Although allocating depreciation and amortization on special facilities differently between gas-only and condensate gas leases.

losses on two wells located in the East Cameron Block 49 (No. A–2) and in the Vermilion Block 96 field (No. 1372), respectively, which were abandoned in September 1959.[175] The Allocation of combination lease joint production expenses to gas here also reflects the previous mentioned differences in method, Continental allocating combination lease expense in the ratio of the Btu equivalents of 1959 Cameron gas and liquid production, while Staff again allocates these expenses, including overheads, in the ratio of lease gas and liquid gross revenues.

Staff's method computes a Cameron area gas production expense of $787,226 corresponding to Continental's $1,207,152, to which is added special facilities depreciation and amortization (Staff, $6,897, Continental, $7,395) and allocated production taxes (both, $31,216).[176]

With a 9% return ($454,966) on a gas net investment (as corrected with respect to special facilities $4,781,635), and a computed gas production working capital ($262,435),[177] Staff's method yields a gas production cost of service of $1,279,305 or 12.77¢ per Mcf, with no allowance for tax benefits.

Staff accepts Continental's company-wide exploration department net investment ($54,806,506) and its portion of general company investment allocated to that department ($827,027). Adding an allowance for working capital ($4,686,387) and employing its "illustrative" rate of return (9%), Staff obtains an exploration department return of $5,401,793 which is allocated (13.417%) to gas ($724,759), on the basis of a modified Btu method which applies an "economic" weight of four to the Btu of oil.[178]

Likewise Staff accepts Continental's computed five-year average exploration expense ($40,421,430) and allocated general and administrative expense ($706,996), of which $5,518,201 is allocated to gas on the same modified Btu basis as before (13.417%).

Total exploration expense and return allocated to gas ($6,242,960) produces an average cost, for Continental's five-year average production of 136,950,646 Mcf, of 4.56¢ and a Cameron area exploration cost of $456,655.

Applicability of Continental's Cost Results to Other Applicants

Continental's cost of service constitutes the formal cost presentation of each of the other three Applicants.

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[175] Staff's cost of service witness treats the writ-off of these intangible drilling costs as out of period or non-recurring, stressing that the write-off of $100,118 for the Block 49 well should have been anticipated and effected before the test year. Staff's supervisory engineer testified, in effect, to handling both write-offs over the productive life of the Cameron reserves rather than as charges to expenses in the year of abandonment. Under the latter method the intangible drilling cost applicable to the A–2 well would have been charged to the reserve in 1958 and the investment in the Block 96 well would have been so charged in 1959. While the reserve would have suffered a resulting deficit in each year the continued operation thereof would eventually recoup all such losses. Also, as a related matter for rate purposes, at least, the investment would be netted only against the continuing annual reserve provision. The latter witness computed that under such a plan expenses would be increased for the year 1959 by $608, the amount by which the return on the normalized part of the investment exceeds the reduction against the lease by lease method of amortization employed by Continental. A 9% rate of return is assumed.

[176] After minor corrections pertaining to special facilities.

[177] Supported as to the challenged materials and supplies item by the testimony of Staff's qualified supervising engineer.

[178] Except for the weighting the total Btus of gas and oil production are the same as those used by Continental in obtaining its exploration department allocated unit cost (16.03¢ per Mcf) to-wit: 287,787,510 total Btu for oil and 178,378,216 total Btu for gas. Staff's weighting by the factor of four treats oil as having, in effect, a Btu equivalent of 615,150,040 units.

Direct costs associated with the CATC-Cameron properties are substantially identical as the interests of each of the Applicants in the leases here involved are equal [179] and Atlantic, Cities, and Tidewater seek to demonstrate that production department overheads and cost of exploration developed by Continental lie within the range of their corresponding costs.

The ratio of Continental's 1959 production department overheads to direct lease expense, excluding production taxes, is 48.13%, while the corresponding ratios of Atlantic, Cities and Tidewater are, respectively, 46.38%, 42.47%, and 40.78%. While the effect of these variations are not shown the weighted average ratio amounts to 45.16% and any adjustment would be small.[180]

Further, in the matter of exploratory operations, using five year averages of net investment, expense, and production, as did Continental, Atlantic, Cities, and Tidewater derive unit costs of 14.07¢, 9.94¢ and 11.02¢ per Mcf as compared with the former's 16.03¢ per Mcf.[181]

With respect to Cities' and Tidewater's results it appears that general investment and overheads were not included. Accordingly, providing for these items in the same ratio as in Continental's case the arithmetic average result becomes 12.83¢ per Mcf, assuming the allocation of costs to gas by the Btu method of allocation and a return at 14%, along with Applicants' provision for income taxes.[182]

Thus, the application of Applicants' procedure produces a unit cost of service which totals approximately 40.47¢ per Mcf, or 189% of the price negotiated with Tennessee.

However, it is not clear from the record whether Continental has or has not used its witness' reduced estimate of Cameron reserves as a factor in determining the CATC-Cameron gas depletion and amortization expense. Assuming that the reduced estimate has been so used the depletion ($5,332) and amortization ($726,308)[183] expenses should be reduced approximately in the ratio of the remaining recoverable reserves found by Applicants' reserve witness and those which are hereinbefore accepted for the purpose of this proceeding (650,065 Mmcf and 1,244, 363 Mmcf, respectively), or by 52.24%, effecting a reduction in the Cameron Area 1959 gas cost of service of 3.8¢ per Mcf.[184]

Basic Criticism of Proposed Methods of Allocation—The Btu Method

Interveners' evidence is, in brief, that Btu content does not constitute the basic characteristic of oil, condensate, and gas. Their fuel expert testified that 98.7% of crude oil is used as a charging stock for processing into gasoline, jet and diesel engine fuel, kerosene, furnace oil, lubricating oils and greases, road oils, asphalt

[179] Continental's ⅝ths additional interest in certain MCN acreage is apparently of no substantial effect.

[180] Reducing production department gas operating expenses by some $3,879. While the Applicants do not refer to the applicability of Continental's allocation of production department general investment the total allocated by the latter to the Cameron Area, if relevant, amounts to but $175,414 of a total production investment of $5,200,253 plus special facilities of $230,031.

[181] Applicants' evidence is to the effect that unsuccessful exploration costs are not identifiable with any specific area of operations or with any particular type of production and that costing of this item on a restricted area basis would frequently result in impractically high exploration costs in areas of low production and in low exploration costs in areas of high production.

[182] As each Applicant has the same proportionate interest in the CATC-Cameron Area properties the use of an arithmetic average is more appropriate than that of any one of the foregoing computations; Continental's ⅝ths interest in certain MCN acreage being apparently of no substantial effect in this respect.

[183] Using a figure which omits Continental's separate interest in the CATC-MCN unit and which includes amortization in minor amount for the Cameron special facilities.

[184] Obtained by $731,640 × .5224 divided by the 10,014,362 Mcf produced in 1959.

and other products, including residual oil and coke; gasoline is the principal of all of these products, accounting for some 40% to 45% of total volume, and some 60% to 65% of total value, of principal refinery products; the hydro-carbon liquid components of condensate (API 50° gravity or higher) are as much as 90% within the gasoline range; natural gas, generally consisting of some 90% of the true gases methane and ethane, is used fundamentally for burning in stationary installations designed principally to produce heat; the price of crude oil is not based on heating value but principally upon the basis of the amount of commercial grade motor or aviation gasoline recoverable therefrom;[185] refineries generally seek to maximize gasoline and additional high octane components at the expense of the heavier hydrocarbons;[186] and that the special value of gasoline inheres in its compact and mobile form. The witness is of the further opinion that the basic purpose of exploration is the discovery of crude oil.

On the other hand, Applicants evidence is to the effect that while Btu do not measure all physical characteristics of liquids and gas, nevertheless as some 90% of the crude oil produced in the U.S., as well as an even higher percentage of natural gas, is used for purposes primarily concerned with the development of heat energy, Btu do reflect a basic utilization of a major portion of these products. Also that Btu content generally corresponds with weight and thus accords recognition to all hydrocarbon products, including those not used for heat energy purposes, such as lubricants and petroleum oils; the Btu content is generally used as a common measure for all fuel and energy sources; and that as oil discovery is not separable from gas discovery, or vice versa, and as one cannot predict the content of a reservoir or the predominant form of the petreloum gas, crude oil, or condensate laden gas which may be encountered, exploration is in general a search for hydrocarbons.

However, in view of the fact that major crude oil components are processed for uses which have no relationship to, or basis of comparison with, the dominant use of natural gas, a simple unmodified Btu method of allocation is too inexact to be of direct use in determining the costs of exploration and production attributable to natural gas.

The Modified Btu Method

Staff uses a weighting of the Btus of liquids and gas in the ratio of 4 to 1 as was done in Commission's Opinion No. 338 in the *Phillip's* case.[187] In relation to the allocation of exploration costs the Commission in that decision observed that comparing these products upon the basis of a common physical characteristic reflected only in part the potentialities of the several hydrocarbon products and, to be practicable for the allocation of costs, must be modified by the exercise of judgment in consideration of fuel values, market factors, and economic trends. The conclusions relied upon by the Commission for so modifying the relative Btu content of oil and gas (6:1) by an economic factor (4:1) which produced an allocation ratio of 24:1 were that: while exploration cannot be entirely responsive to market price it is directed toward obtaining salable products and, therefore, market relationships should be reflected in the allocation; the demand for natural gas has been expanding faster than that for domestic produced crude oil; in exploration and production casinghead-gas has now come to be considered as a co-product of crude oil and, in connection

[185] Among normal crudes the higher the API gravity the higher the gasoline potential and the higher the price of the crude, the Btu content per gallon dropping from 154,000 for API 10° to 115,100 for API 80° gravity.

[186] Some 65% of major petroleum products is used for transportation purposes while virtually no natural gas is so used. Further in 1958 the volume of liquefied petroleum gases so used was equal to but 1.4% of the domestic demand for gasoline.

[187] *Phillips Petroleum Company,* Docket No. G–1148, et al., issued September 28, 1960, 24 FPC 537.

with condensate wells, equal consideration is given by producers to the discovery of both liquids and gas; and, because of these matters, in allocating joint exploratory and development costs (of Phillips) it is appropriate to give increased consideration to Btu relationships. Also, in order that producers may be encouraged to anticipate and supply growing demands allocations must be so applied as to encourage exploration and development for gas as compared with oil and to provide the producer (Phillips) with funds sufficient to meet future costs of exploration and production. Upon the basis of such considerations, and on the record in that proceeding, the Commission found the proper economic factor to be applied to the straight Btu content of oil to allocate Phillips' test year exploration costs to be four so that cost relationship of finding one Mcf of gas to one barrel of the higher Btu oil would be about one to twenty-four. The Commission remarked that extrapolation to 1958 of the 1951–1956 actual trend in oil and gas prices would also produce the same ratio (24 : 1).

There is no direct support in this record for the application of an economic factor to the Btu of oil. It does appear that in the seven Southwestern States realization for oil has increased from $1.967 per barrel in 1947 to $3.06 in 1958, while that for gas has increased from 3.76¢ to 10.86¢, or from a relative oil-gas ratio of 52 :1 to one of 28 :1.[188]

Conclusions such as those upon which the Commission relied in the Phillip's decision are generally supportable upon the record in this proceeding, but the evidence which concerns Continentals's operations and the price relationships of liquids and gas does not sufficiently support the application of the specific Phillips economic factor in this proceeding. The use by Staff of the factor is therefor subject to considerable reservation.[189]

Imputed Cost Method

Interveners and Applicants separately sponsor technical testimony concerning the operating mechanics of a gas condensate reservoir—the former to establish a foundation for using computed company-wide gas-only on-lease costs and computed company-wide oil-only on-lease costs, as well as corresponding relative investment costs, to allocate on a relative cost basis, respectively, Cameron on-lease expenses and on-lease net investment of those 23 leases which produce both gas and liquids.

Interveners' evidence is to the effect that as to hydrocarbon components there is no sharp line which distinguishes natural gas, crude oil, and condensate; condensate (API 48° gravity or higher) is in fact a low specific gravity crude; generally, in single phase reservoirs, condensate exists as a gas phase liquid dissolved in natural gas in place; and, with a decline in pressure and temperature below dew point conditions the condensate will liquefy in droplets which become entrained with and lifted by the gas.

The testimony of Applicants' expert, a practiced reservoir and production engineer, on this point is, in general, that condensate is neither a crude nor, at the elevated pressures and temperatures of reservoir conditions, a liquid; condensate, at 50° API gravity or greater, is composed of straight chain hydrocarbons lighter than octane and is a gas in the reservoir, flowing as a gas into the well, and up the well-bore;[190] the condensate vapor and gas behaving as a gas mixture to the well mouth, the energy contribution of one is indistinguish-

[188] The ratio for Louisiana for the latter year (1959) was approximately 25 : 1.

[189] Staff made no effort by testimony of witnesses or by reference to any portion of the evidence of record in this proceeding to support use of any specific economic factor, but simply relies upon its use in the *Phillip's* decision. Indeed, as far as the evidence in this case is concerned, the factor could be any other number as well as 4.

[190] According to Applicants' witness any mist which may form as the gas flows up the well-bore will have all the characteristics of a gas.

able from that of the other; and the mechanical work involved in producing a gaseous unit is trivial. On the other hand there is no disagreement between the witnesses that crude oil is a liquid in the earth, flows through the reservoir and is produced as a liquid, and that there is no comparability in the nature and kind of costs incurred in operating condensate and crude oil reservoirs.

Interveners' foregoing witness, a specialist in petroleum engineering, testified to basic laws only and made no study of the CATC-Cameron reservoirs and collected no information concerning the fluid content thereof.

The 23 CATC-Cameron condensate and the three dry gas wells are comparable in depth, have substantially the same sub-surface temperatures and pressures, and are each produced and operated as a gas well. The gas from both types of leases runs through identical pressure dehydration and separation equipment, and, except for a $2,000 condensate filter, production of liquids requires no special field equipment in addition to that used for production of gas on the dry gas leases.

The weight of the evidence thus clearly fails to support the use in this proceeding of on-lease costs derived from Continental's company-wide oil-only leases to allocate a portion of CATC-Cameron combination lease investment and production expense to liquids.

Risks and Rate of Return

Offshore activity of the industry commenced with initial exploratory efforts in the shallow and protected waters of the Gulf and the discovery of the Creole field in 1938. By 1959 the offshore industry had leased 3,357,117 acres, drilled 2,843 wells, spent $2,594,000,000 in direct lease investment, produced 258,865,699 barrels of oil and condensate and 842,390,293 Mcf of natural gas, and had received $725,000,000 in gross revenues.

Of the Louisiana offshore wildcats 35% have been successful as compared with 11% of the total domestic.

As it may take from three to five years after an offshore discovery before revenues are realized and initial investment is high only the larger and better financed operators can undertake the risks involved.[191]

Accordingly, the CATC companies in 1946 combined to share the risks of offshore operations. By 1959, Applicants had spent $284,785,000 compared with revenues received of $67,492,000.[192]

In the Cameron general area Applicants took some 59 leases covering 238,629 acres of which all but 11 leases on 38,750 acres have been surrendered. However, of 243 CATC offshore wells drilled 53% have been successful and of 39 Cameron area wells 66% have been successful. Nevertheless, Applicants' witness makes the significant point that operators have sought to explore and develop the more promising offshore structures and eventually a decline in the success ratio is to be expected as the less attractive prospects are drilled.

Hazards and risks peculiar to offshore drilling concern collision, blowouts, fires, and hurricanes. These have involved as to the CATC group the 1959 collision of a freighter with its Eugene Island Block 208B platform,[193] platform and tender damage from the hurricanes of 1956 and 1957,[194] limitedly, blowouts occurring at

[191] Large and costly reserves necessitate comparatively fast rates of production. Louisiana allowables for a capable offshore oil well within the territorial limits of the State are 1½ times that of an onshore well, but due to current reductions allowables applicable to offshore operations are now but some 35% of those in effect when offshore operations first attained significance.

[192] As related to the whole offshore area including Cameron, Eugene Island, and West Delta leases.

[193] Estimated platform damage $750,000.

[194] All platforms suffered damage.

the Cameron Block 49A–1 well and Eugene Island Block 208B–3 well, [195] and more markedly a fire on the West Delta Block 45E platform which commenced on October 15, 1958, and lasted for two months, with well workovers continuing to February 29, 1960.[196] This fire required heavy equipment and major drilling operations to bring under control. Seven lives were lost. The contractor's drilling rig, the CATC platform and living quarters, production facilities, all rental equipment, and seven multiple completed wells were lost or destroyed, along with an estimated 750,000 barrels of oil.[197] In addition, production of 436,000 barrels of oil was deferred and the reservoirs probably suffered extensive damage.

No participant questions that the risks involved in exploration for oil and gas and the development of oil and gas properties, particularly those offshore, are greater than risks associated with the business of refining, marketing, and transportation;[198] nor that inability to forecast the success of a new investment in production properties and absence of a direct monopoly market serves to differentiate Applicants' jurisdictional operations from those of a typical public utility. Interveners do attempt to show that the increasing demand for natural gas offers the natural gas producer a more assured market than that available to the crude oil refiner, but this subject involves complex matters not adequately developed in the record and for which no answer now available is better than that offered by Applicants' witness in his proposed resort to an earnings investment ratio.

Rate of Return

Applicants' rate of return witness testified to average rates of return on book net assets obtained over the past 12 years (1947–1958) by a broad range of general industry groups which include the petroleum production and refining industry and 64 others.[199] The compilation represents in all some 3,600 leading corporations, to which the witness has added results obtained for 10 selected larger producers whose operations are confined to the production of crude oil and natural gas (Class A), and for 25 selected larger integrated producers whose operations embrace non-producing activities including refining and marketing. He made no study of the industries as to their specific risks and stability of earnings on the ground that under present conditions the comparative return on investment satisfies all other tests and, that specifically, the earnings of the oil and gas producers reflect the risks and requirements of the type of business in which the gas producers are engaged.

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[195] Bridged over after flowing uncontrolled for short periods of time.

[196] The fire started just after drilling of the seventh well was completed. There were a total of 19 completions in all seven wells. Each well had at least one completion burning along with the fire in the four completions in the seventh well. The platform, as a junction, was connected by pipeline with four other platforms and the production from the other platforms was also shut off for a period of time.

[197] Fire control operations, platform damage and destruction, and restoration operations entailed a net loss after insurance of $4,139,000, not including probable reservoir damage and any liability resulting from third-party legal claims being asserted in pending actions at law.

[198] Interveners question the use of the exploratory well 1:9 success ratio as a measure of risk on the grounds that a large operator drilling many exploratory wells is all but assured to a mathematical certainty a success rate of 10%. However, Applicants' evidence discloses that the 1:9 drilling success rate is not a commercial success rate. In any event this single factor is of little specific importance in the case.

[199] From First National City Bank's Monthly Letters, "Business and Economic Conditions". The rate of return at this point is not conventional but consists of net income after interest and taxes divided by book net assets which comprise the common and preferred equities.

The petroleum production and refining industry group (121 companies) had an average return after taxes of 14.9% over the past 12 years,[200] ranking relatively high because of the risky nature of the business and the requirements of growth and expansion which consumers' demands have imposed upon the industry. Similarly, the average return for the Class A petroleum companies was 21.3% and for the Class B group 15.5%.

Continental is a Class B type company, vertically integrated, is active in exploration, production, manufacturing, marketing, and transportation phases of the oil and gas business, and is engaged as well in petrochemical manufacturing and marketing, and in the transportation of natural gas in liquid form by tankers. However, the witness identifies Applicants' natural gas business as similar in risk and requirement to the Class A petroleum companies.

Considering the foregoing indicated earnings experience of both regulated and unregulated business, and the higher relative demand for natural gas as compared with oil, the witness concludes that the upper portion of the range of rates of return for the Class A petroleum companies (21.3%, above) is applicable to Continental's natural gas production, and supports a fair rate of return for major natural gas producers, such as Applicants, of 20% to 25% on net investment,[201] or 12% to 15% with an allowance for income tax benefits.[202]

The witness characterized offshore single ventures such as that of the CATC group as having natural risks which are accentuated by the difficult nature of sea area operations, and by the necessity of committing large sums of money far in advance of the time of actual commencement of commercial operations, and testified that the proper rate of return in such instances would be materially higher than those for company-wide operations by a major natural gas producer, or not less than 14% plus allowance for taxes computed on the basis of statutory benefits.

The witness also computed what he referred to, in substance, as the life-time "true rate of return," [203] consisting of that discount rate which would equate respective present values when applied to (a) estimated total capital outlays and (b) estimated revenues less estimated operating expenses and actual income taxes.[204] While testifying that the "true rate of return" (10.0% and 11.2%, depending upon prices used) after cash operating expenses and taxes could not be directly compared with his recommended cost of service rate of return, and commenting on the range of possible errors involved in calculations based on allocations, the witness states that the "true rate of return" provides an indication of estimated average return likely to be earned over the life of the property, takes cognizance of the lengthy time lag between the making of an

[200] As reported by the First National City Bank of New York, N.Y.

[201] Ratio of net income after actual taxes but before interest charges to the depreciated net property account plus working capital which effects a return of 21.8%, as compared with the 21.3% return indicated on the page, above, for the Class A group.

[202] Before consideration of the time lag between making capital investment and receiving income therefrom which, he stated, characterized the CATC Cameron project; a matter that could be generally cared for, broadly, by charging interest during construction.

[203] Discounted cash flow rate of return.

[204] Using Continental's estimate of its one-fourth net salable reserves of Cameron gas (150,904 Mmcf) and condensate (1,143,000 bbs.) net after royalties, and annual production through 1982 and remaining life; a price for gas (21.4¢ per Mcf for one result, and the contract escalated price for another) and for condensate ($3.18/bb.) to obtain estimated total revenues (gas, $32,293,600 and, $38,403,000, respectively; condensate, $3,635,200); accumulating 1947–1959 capital outlays and adding estimated limited future capital outlays (total $9,915,100); and, accumulating past operating expense together with allocated exploration and production department and general overheads, and adding estimated future expenses and allocations ($10,612,200), and income taxes ($3,632,900 and $6,015,000, respectively).

investment and obtaining income therefrom,[205] and represents the minimum level of return below which management would ordinarily refuse to commit new funds to the development of a project. This method's necessary reliance on estimates that run far into the future renders it of doubtful usefulness.[206]

The foregoing discussion of risks establishes the similarity of Applicants' offshore operations to those represented in Applicants' witness' Class A producers, for which the witness computes the average 1947–1958 return to be 21.8% (Exh. 23) or some 14.9% with the tax allowance.

However, computing the return for this group for the five year past period, (1954–1958, Exh. 23) and weighting inversely to give effect to the relative closeness of each figure to 1958 the average return becomes 16.2%, which is here accepted as a reasonable return for the purpose of this proceeding.

The Tax Allowance

The problem posed, for the claim by Applicants of either a tax allowance or an equivalent higher rate of return, by the holding of the Court of Appeals for the Fifth Circuit in *El Paso Natural Gas Company* v. *FPC*, 281 Fed 2d 567, 573 (1960) to the effect that the record must afford a basis for a finding on the amount of tax benefits actually necessary to provide an increment for incentive, is substantially answered by Applicants' witness' showing of the ratio of earnings to book net investment plus working capital for the Class A producers. The earnings are after actual taxes and the weighted average ratio of 16.2% indicates the return required to enable the company to obtain its necessary capital in competition with other like companies in the industry. The return approval dispenses with the necessity of giving further consideration to the question of incentive.

Actual Taxes

As the return for Applicants' Class A producers is after taxes there has to be considered the matter of allowing for taxes with respect to the Cameron properties computed by the taking of all deductions.

In connection with the development of its so-called discounted cash flow rate of return Applicants compute an income tax with deductions in the estimated amount of $561,000 for 1959. The company as a whole however, on this basis pays no income taxes. There is no satisfactory basis in the evidence for treating the Area seperately, at least, so long as it is allocated exploration expenses incurred company-wide, and considering the manner in which the rate of return has been determined, hereinabove, no provision for income taxes would be proper in the premises.

Cost of Service Computations Adjusted for Return

For the reasons hereinbefore stated in consideration of the several methods of allocation, neither Applicants' nor Interveners' cost results can be accepted, and Staff's unsupported use of an economic factor can be accepted to obtain a result which will serve only as an indication of the level of an acceptable rate.

Accordingly, adjusting the previous figure found by Staff's method of production department return ($453,966) for the 16.2% rate of return, above, to $817,139, and the company over-all exploration department return ($5,401,793) to $9,723,227 of which $1,304,565 is allocated to gas there is obtained an adjusted total Cameron Area gas cost of production of $1,642,478 and gas cost of exploration of $498,715 for a total Area cost of gas of $2,141,193 which produces a unit cost of 21.38% per Mcf.

[205] Ten years in the instant of the CATC-Cameron project; a situation which admittedly, however, could be generally alleviated by capitalizing interest during the period of lag.

[206] Further, the witness has relied upon an estimate of reserves which has not been accepted in this decision.

However, if costs had been considered on any basis in 1957, when these proceedings were first heard, the lower levels of cost, as indicated by Applicants' witness' indices, would have yielded a somewhat lower unit cost of gas. It appears that Cameron Area capital expenditures increased some 10.3% in the years of 1958 and 1959, the cost of drilling and equipping offshore Louisiana wells some 9.1%, and operating expenses (labor) some 8.5% in the same period. Applying these changes as the only data available to obtain an approximation of costs as of 1957 it would appear that the foregoing 21.38¢ would be reduced by some 0.8¢ per Mcf to a cost of 20.58¢ per Mcf.[207]

In view of the limited consideration which can be given Staff's method due to the unsupported use of an economic factor the 20.56¢ is accepted as substantially confirming the result previously obtained herein of 19.92¢ per Mcf. In the circumstances of the record to which Applicants have in part contributed, and in the matter of a price to be used to condition the issuance of a certificate, the latter are entitled only to that finding which accepts the 19.92¢ per Mcf as the reasonable price.[208]

The Applicable Date

The reasonable price has been determined as if considered and fixed at the time of the issuance of the original certificate of June 24, 1957, as the authorization to Applicants must relate back in order to provide Applicants with the necessary statutory authorization for the initial service to Tennessee. To provide other prices would improperly import into the case matters in the nature of rate relief to the Applicants prior to the earliest definite date (November 1, 1962) contractually provided for the purpose.

FURTHER FINDINGS

Applicants are qualified and able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Act and the requirements, rules and regulations of the Commission thereunder;

The herein proposed service, sale, and operation of the Applicants has been, is, and will be required by the preceding, present, and future public convenience and necessity;

However, it is further found that, pending a determination in an appropriate rate proceeding or proceedings effective as to Applicants or any of them, the reasonable price to have been and to be charged by Applicants to Tennessee therefor, from the date of initial service in the premises, is 19.92¢ per Mcf; and that public convenience and necessity requires that the certificates hereinafter issued to Applicants severally shall, in the manner hereinafter provided, be conditioned accordingly.

Applicants shall be required to refund with interest at 6% the difference between sums received from Tennessee for gas delivered from the CATC-Cameron Area under their respective contracts of August 1956, with the date of initial delivery thereof to the date this order shall become effective, and the sums which would have been received had the charge for such deliveries been 19.92¢ per Mcf as hereinafter provided, less amounts relating to taxes paid or held in reserve therefor.

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[207] If adjusted for rate case expense the 20.58¢ would be increased by approximately 0.2¢—using a five year amortization and allowing a return on the average unamortized amount.

[208] Adjustments proposed to Staff's Cost of Service and appropriate with respect to reserves are approximately offsetting.

NOTICE

The Intervener Tennessee is on notice that the refund hereinafter provided shall be subject to such directives or orders as may be issued by the Commission at any appropriate future date.

ORDER

Upon consideration of the record herein, the contentions set forth in the proposed findings and in the briefs of respective counsel, and for the reasons and upon the findings and conclusions set forth in the foregoing portions of this decision, of which this order is a part,

IT IS BY THESE PRESENTS ORDERED, subject to review by the Commission on appeal, or on its own motion, as provided by its Rules of Practice and Procedure, that:

(A) A permanent certificate of public convenience and necessity shall be, and is hereby, issued to The Atlantic Refining Company (Atlantic), Continental Oil Company (Continental), Cities Service Production Company (Cities), and Tidewater Oil Company (Tidewater) as applicants, severally, authorizing the services and sale, proposed and provided respectively, by:

(a) Atlantic in its contract with Tennessee Gas Transmission Company (Tennessee) dated August 10, 1956, and filed as the former's FPC Gas Rate Schedule No. 185, as amended;

(b) Continental in its contract with Tennessee dated August 17, 1956, and filed as the former's FPC Gas Rate Schedule No. 154, as amended;

(c) Cities in its contract with Tennessee dated August 14, 1956, and filed as the former's FPC Gas Rate Schedule No. 6, as amended;

(d) Tidewater in its contract with Tennessee dated August 14, 1956, and filed as the former's FPC Gas Rate Schedule No. 72, as amended;

and, in each instance the operations and construction reasonably necessary thereto;

(B) Each certificate issued severally to Applicants as provided in Paragraph (A), above, shall be, and is hereby, conditioned so that the base price effective under each of the aforesaid contracts, from the date of initial service thereunder, shall be, until lawfully changed in the manner provided by the Natural Gas Act, 19.92¢ per Mcf;

(C) Each of the aforesaid Applicants shall, within 60 days of the date upon which this order shall become effective, refund to Tennessee with 6% interest a sum equal to the difference in the base price charged Tennessee and the price specified in the condition provided in Paragraph (B), above, of 19.92¢ per Mcf, applied to all volumes delivered to Tennessee under the contracts which form the subject matter of this proceeding (Paragraph (A), above, from the date of initial delivery to Tennessee;

(D) Within 10 days of the date of refund provided in Paragraph (C), above, applicants shall, each of them, file with the Commission an officially certified statement showing the amount of the refund, its manner of computation, and the interest payments related thereto, and a statement from Tennessee acknowledging the receipt;

(E) The certificates issued to Applicants shall be deemed accepted and of full force and effect, unless refused in writing and under oath by them within 30 days from issuance of this order;

(F) The certificates issued to Applicants are not tarnsferable and shall be effective only so long as they continue the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act, and the applicable rules, regulations, and orders of the Commission;

(G) The grant of the certificates to Applicants herein is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against them.

EWING G. SIMPSON
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

MIDWESTERN GAS TRANSMISSION COMPANY, DOCKET NOS. G–16841, RP61–19 AND CP61–38

ORDER AMENDING ORDERS ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND ACCEPTING RATE FILINGS

(Issued January 23, 1962)*

On October 16, 1961, Midwestern Gas Transmission Company (Midwestern) filed separate motions to amend the certificate orders issued to it in Docket Nos. G–16841 and CP61–38 on May 12, 1959, (accompanying Opinion No. 320), and July 27, 1961, respectively, 21 FPC 653 and 26 FPC 201.

The order in Docket No. G–16841 authorized Midwestern to sell natural gas to three distributors in the Chicago area, Peoples Gas Light and Coke Company (Peoples), Northern Illinois Gas Company (Northern Illinois) and Northern Indiana Public Service Company (NIPSCO), said gas to be delivered at Joliet, Illinois, into the facilities of Chicago District Pipeline Company (Chicago District) for transportation to the three distributors. This authorization also provided that the gas delivered to the three distributors at the common Joliet delivery point may be interchanged between all three distributors so long as the total deliveries to the three companies do not exceed the sum of their authorized contract demands.

The order of July 27, 1961, in Docket No. CP61–38 authorized Midwestern to establish a new delivery point near Gilman, Illinois, for the delivery of gas to Northern Illinois to enable the latter to develop a new underground storage field and to furnish natural gas service to the Village of Crescent City and the City of Watseka, Illinois. This order was conditioned on Northern Illinois receiving a certificate from the Illinois Commerce Commission approving the plan to develop the storage project near Crescent City.

By its motions of October 16, 1961, for amendment of the authorization granted in Docket Nos. G–16841 and CP61–38, Midwestern recites that it proposes to establish a third delivery point to Northern Illinois at Kankakee, Illinois, in order to effect certain operational advantages in Northern Illinois' existing service in Kankakee, which new delivery point Midwestern apparently believes is within the purview of Section 2.55 (c) of the Commission's Rules of Practice and Procedure; recites the authorization obtained for the delivery point to Northern Illinois at Gilman, Illinois, in Docket No. CP61–38; and requests that the aforesaid authorizations be amended so as to eliminate application of the provision for the interchange of gas between the three distributor customers to the new delivery points, confining said interchange authorization to gas delivered at Joliet.

*Amended by order issued March 1, 1962, 27 FPC 424.

In view of the fact that Northern Illinois' present service to Kankakee is supplied directly from the system of Chicago District Pipeline Company which contains a mixture of gas purchased by Northern Illinois from Midwestern and gas purchased from Natural Gas Pipeline Company of America, it appears questionable whether Section 2.55 (c) of the Rules applies to the new delivery point at Kankakee; therefore the motion to amend in Docket No. G–16841 will be interpreted to request authorization also for the proposed new delivery point from Midwestern to Northern Illinois at Kankakee.

On November 24, 1961, Midwestern filed a further motion to amend the certificate authorization of July 27, 1961, in Docket No. CP61–38 to enable Midwestern to commence service to Northern Illinois at Gilman for the communities of Crescent City and Watseka immediately, without awaiting fulfillment of the condition requiring final approval by the Illinois Commerce Commission of the development of the proposed storage project near Crescent City. Inasmuch as the Illinois Commission has approved the service to the two communities and the construction and operation of the facilities necessary therefor, and such service is not connected with or dependent upon the storage project, it is reasonable to permit the establishment and use of the proposed Gilman delivery point for service to Crescent City and Watseka, reserving, however the commencement of service for development of the storage project until full approval therefor has been secured from the Illinois Commission.

No change in authorized sales volumes by Midwestern will result from the proposals.

On August 2, 1961, Midwestern tendered its Rate Schedule CD–1 (being original Sheets Nos. 8A, 8B, 8C and 8D to FPC Gas Tariff, First Revised Volume No. 1) and a superseding service agreement with Northern Illinois dated July 20, 1961. The new Rate Schedule CD–1 is identical with presently effective Rate Schedule CDX–1 except that the former is available to any buyer whose system connects or can be made to connect with Midwestern's main transmission line between Portland, Tennessee, and Joliet, Illinois, and that it does not contain a provision for the interchange of gas between buyers. The proposed superseding service agreement is identical with the presently effective service agreement except that it provides for delivery of gas at an additional delivery point near Kankakee, Illinois.

It should be noted that by order issued February 13, 1961, in Docket No. RP61–19, the Commission instituted an investigation of the rates of Midwestern, especially insofar as the rates applicable to Midwestern's southern system (the portion of its system involved in the two subject dockets) are concerned.

The Commission finds:

It is in the public interest and appropriate in carrying out the provisions of the Natural Gas Act to amend as hereinafter ordered the orders of the Commission granting certificates of public convenience and necessity to Midwestern Gas Transmission Company in Docket Nos. G–16841 (accompanying Opinion No. 320) and CP61–38, respectively.

The Commission orders:

(A) The order of the Commission issued May 12, 1959, in Docket No. G–16841 (accompanying Opinion No. 320) be and the same is hereby amended by adding the following sentence to Ordering Paragraph (D) thereof:

However, the requirements of this paragraph shall be applicable only to the sale of gas by Midwestern to Peoples, Northern Illinois or NIPSCO under the terms of Gas Service Agreements providing for a sole point of delivery at the intersection of the facilities of Midwestern and Chicago District near Joliet, Illinois.

(B) Said order issued May 12, 1959, in Docket No. G–16841 (accompanying Opinion No. 320) is further amended by adding thereto a new Paragraph (J) to read as follows:

(J) Midwestern is hereby authorized to establish a new connection between its transmission system and the facilities of Northern Illinois at a convenient point near the Town of Kankakee, Illinois, for the delivery of heretofore authorized natural gas to Northern Illinois, subject to the condition contained in the last sentence of Paragraph (D) as hereinbefore added to said Paragraph.

(C) The order of the Commission issued July 27, 1961, in Docket No. CP61–38 be and the same is hereby amended by deleting therefrom Ordering Paragraph (D), and by adding a new Paragraph (G) to read as follows:

(G) The deliveries of natural gas for the testing and development of storage and for service to the aforesaid communities are to be made from Northern Illinois' existing authorized contract quantity from Midwestern. These deliveries are to be made pursuant to Midwestern's FPC Gas Rate Schedule CD–1 and the related gas service agreement between Midwestern and Northern Illinois dated July 20, 1961.

(D) Said order issued July 27, 1961, in Docket No. CP61–38 be and the same is hereby further amended by deleting therefrom the existing Paragraph (B) and substituting therefor the following:

(B) The certificate granted in Paragraph (A) above is hereby conditioned, as to the development of the proposed gas storage project near Crescent City, upon Northern Illinois receiving the requisite approval therefor from the Illinois Commerce Commission. The proposed delivery of natural gas to Northern Illinois for service in the communities of Crescent City and Watseka is hereby authorized to commence upon the date on which this amending order issues.

(E) Midwestern's tendered FPC Gas Rate Schedule CD–1 and the concurrently tendered gas service agreement between Midwestern and Northern Illinois dated July 20, 1961, are hereby accepted for filing, effective upon the date on which this amending order issues.

(F) Midwestern's aforesaid Rate Schedule CD–1 is hereby made subject to investigation in the proceedings in Docket No. RP61–19.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

PENNSYLVANIA POWER & LIGHT COMPANY, PROJECT NO. 1881

ORDER APPROVING REVISED PROJECT EXHIBITS

(Issued January 23, 1962)

Application was filed on September 27, 1961 by Pennsylvania Power & Light Company, licensee for major Project No. 1881, for Commission approval of revised Exhibits L and M so as to authorize and show the conversion of Unit No. 6 from 25 to 60 cycle operation, which is the last 25 cycle unit in the Holtwood powerhouse.

The licensee states that such conversion is necessary inasmuch as the remaining 25 cycle load has decreased to the point where it is now more economical to supply that load from the Lancaster Division local distribution system through frequency changer sets at the load site. The conversion will also make available increased quantities of power for the licensee's growing 60 cycle load.

The Chief of Engineers, Department of the Army, has approved the revised Exhibit L–1–2 (FPC No. 1881–64), which is a general layout of the project structures, insofar as the interests of navigation are concerned.

The Commission finds:

The following described revised Exhibits L and M conform to the Commission's rules and regulations and should be approved as part of the license for the project, and the Exhibits L and M, now part of the license, and hereinafter described as being superseded, should be eliminated from the license—all as hereinafter provided:

Exhibit L–1–2: (FPC No. 1881–64) entitled "General Layout of Structures" superseding Exhibit L–1–1 (FPC No. 1881–56),

L–5–A–3: (FPC No. 1881–65) entitled "Power House—Typical Cross Section—No. 3 Unit," superseding Exhibit L–5–A–2 (FPC No. 1881–57),

L–5–B–4: (FPC No. 1881–66) entitled "Power House—Typical Cross Section—No. 8 Unit," superseding Exhibit L–5–B–3 (FPC No. 1881–58),

L–5–C–3: (FPC No. 1881–67) entitled "Power House—Typical Cross Section—No. 10 Unit," superseding Exhibit L–5–C–2 (FPC No. 1881–59),

L–7–4: (FPC No. 1881–68) entitled "Power House—Sectional Plans and Elevations," superseding Exhibit L–7–3 (FPC No. 1881–61),

M–2A–5: (FPC No. 1881–69) entitled "Electrical Equipment—One Line Diagram, 60—Equipment," superseding Exhibit M–2A–4 (FPC No. 1881–62) and Exhibit M–2B–4 (FPC No. 1881–63), and

M–5: Consisting of 15 typewritten pages, entitled "General Description of Mechanical and Electrical Equipment and Appurtenances," superseding Exhibit M–4.

The Commission orders:

The revised Exhibits L and M described in the above finding as conforming to the Commission's rules and regulations are approved as part of the license for Project No. 1881, and the Exhibits L and M described in the same finding as being superseded are eliminated from the license for the project.

Before Commissioners: Joseph O. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

EL PASO ELECTRIC COMPANY, DOCKET NO. E–7017

ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTGAGE BONDS

(Issued January 25, 1962)

El Paso Electric Company (Applicant), incorporated under the laws of the State of Texas and doing business in the States of Texas and New Mexico, with its principal place of business at El Paso, Texas, filed an application on December 19, 1961, as amended December 28, 1961, for an order, pursuant to Section 204 of the Federal Power Act, authorizing the issuance and sale at competitive bidding of up to $10,500,000 principal amount of First Mortgage Bonds, due 1992.

Applicant proposes to issue the Bonds under its Indenture of Mortgage, dated as of October 1, 1946, between the Applicant and State Street Bank and Trust Company (formerly State Street Trust Company), of Boston, Trustee, as heretofore supplemented and as to be further supplemented by a proposed Seventh Supplemental Indenture, to be dated as of February 1, 1962.

Applicant proposes to invite, on or about January 31, 1962, sealed, written bids for the purchase of $10,500,000 principal amount of First Mortgage Bonds, by

newspaper publication and by distribution of a Form of Proposal, together with a statement of terms and conditions relating thereto and a form of purchase contract. All bids, whether from a single bidder or from a group of bidders, must be for the purchase of the entire issue of Bonds and must be on the Form of Proposal provided by the Applicant, signed by the bidder or by the Representative in the case of a group of bidders. Each bid must specify the interest rate to be borne by the Bonds, which rate shall be a multiple of ⅛ of 1 percent; the price exclusive of accrued interest to be paid to Applicant for the Bonds, which price shall be not less than 100% nor more than 102.75% of the principal amount thereof; and, that Applicant shall be paid the amount of the accrued interest on the Bonds from February 1, 1962 to the date of payment therefor and delivery thereof.

Applicant reserves the right, at any time before 12:00 noon, New York Time, February 5, 1962, to reduce the principal amount of Bonds for which bids are being invited from $10,500,000 to $7,000,000.

Unless postponed, all bids for the purchase of the proposed issue of Bonds must be presented to Applicant at 90 Broad Street, 19th Floor, New York, N.Y., before 11:00 a.m., New York Time, on February 7, 1962. Applicant, unless it rejects all bids or excludes a bid or bids for reasons specified in the terms and conditions set forth in the bidding papers, will accept the bid which provides for the lowest annual cost of money. Each bid must be accompanied by a certified, bank cashier's or official bank check or checks, payable in New York Clearing House funds, in the aggregate amount of $210,000.

Applicant will apply the proceeds of approximately $10,500,000 to be obtained from the proposed issuance and sale of Bonds, as follows: (1) to refund all of its outstanding First Mortgage Bonds, 5⅛% Series due 1989, in the principal amount of $3,500,000, including the payment of duplicate interest of approximately $14,900 and a redemption premium of $257,250; and (2) toward the financing of Applicant's construction program. If Applicant elects to reduce the principal amount of the Bonds for which bids are requested, then all of the proceeds, of approximately $7,000,000, will be used toward the financing of Applicant's construction program.

Applicant estimated that its construction program expenditures would be $778,000 for the last two months of 1961 and $10,179,000 for the calendar year 1962. The 1962 program includes: $6,820,000 for a proposed 80,000 kw turbo generator and boiler expected to be placed in operation in 1963 as Unit No. 2 at Applicant's Newman Power Station; $452,000 for the construction of 115 kv transmission lines from Newman to the Austin substation in El Paso and to the Las Cruces substation; and $2,908,000 for construction of and extensions and improvements to substations and other transmission and distribution facilities.

Written notice of the application has been given to the New Mexico Public Service Commission, the Texas Railroad Commission and to the Governor of each of those States. Notice of the application was also given by publication in the Federal Register on January 3, 1962 (27 F.R. 23), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before January 18, 1962 with the Federal Power Commission, Washington 25, D.C. No protest, petition or request to be heard in opposition to the granting of the application has been received.

The Commission finds:

(1) Applicant, a corporation, owns and operates facilities for the transmission and sale at wholesale for resale of electric energy which is transmitted between the States of New Mexico and Texas, and consumed at points outside the State in which it is generated, all of which facilities are in addition to, and do not include, facilities used for the generation of electric energy, facilities used

in local distribution or only for the transmission of electric energy consumed in intrastate commerce, or facilities for the transmission of electric energy consumed wholly by the transmitter. Applicant is, therefore, a public utility within the meaning of that term as used in Section 201 of the Act.

(2) The proposed issuance and sale of Bonds, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204(f) of the Act; and the proposed issuance of securities is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The proposed issuance and sale of Bonds, upon the terms and conditions and for the purposes specified in the application, as described above, are authorized, subject to the provisions of this order.

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

(C) This authorization shall expire unless the transaction hereby authorized is consummated within 60 days from the date of issuance of this order.

(D) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(E) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States with respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SOUTHERN NATURAL GAS COMPANY, DOCKET NOS. G–9201 AND G–14587

ORDER AMENDING ORDERS ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 25, 1962)

On August 7, 1961, Southern Natural Gas Company (Petitioner) filed a petition to amend the Commission's orders issued November 2, 1955, in Docket

No. G–9201, and August 7, 1959, in Docket No. G–14587, so as to permit Petitioner to transport and deliver to Southern Nitrogen Company (Nitrogen), an existing customer, a maximum of 16,750 Mcf of natural gas per day, of which 10,100 Mcf will be firm gas and 6,650 Mcf interruptible, in lieu of the presently authorized deliveries of 11,000 Mcf per day, of which 6,500 Mcf is firm gas and 4,500 Mcf interruptible.

In Docket No. G–9201 Petitioner was authorized to construct and operate certain facilities in order to sell and deliver a maximum of 11,000 Mcf of natural gas per day, on an interruptible basis, to Nitrogen, a new direct industrial customer. Nitrogen uses the gas as raw material and fuel in the production of nitrogenous fertilizers at its plant near Savannah, Georgia. In Docket No. G–14587 Petitioner was authorized to transport and deliver to Nitrogen up to 6,500 Mcf of the authorized 11,000 Mcf per day on a firm basis.

Petitioner has been advised that Nitrogen proposes to enlarge its facility at Savannah and will require increased volumes of firm and interruptible gas. Nitrogen's requirements are estimated to be:

Period	Maximum daily quantity—Mcf	
	Firm	Total
Presently	6,500	11,000
For 90 days after completion of expanded plant	6,500	14,500
Thereafter and until Oct. 1, 1964	8,700	16,750
After Oct. 1, 1964	10,100	16,750

Petitioner and Nitrogen have entered into an amendatory agreement, dated July 27, 1961, for the proposed additional volumes of natural gas.

The additional deliveries will not appreciably affect Southern's overall gas supply.

Due notice of the filing of the petition to amend and opportunity for hearing thereon has been given by publication in the Federal Register on December 28, 1961 (26 FR 12637). No protest or petition to intervene has been filed in this proceeding.

The Commission Finds:

It is necessary and appropriate to carry out the provisions of the Natural Gas Act, and the public convenience and necessity require that the Commission's orders issued November 2, 1955, in Docket No. G–9201, and August 7, 1959, in Docket No. G–14587, be amended as hereinafter ordered.

The Commission orders:

(A) The Commission's orders issued November 2, 1955, in Docket No. G–9201, and August 7, 1959, in Docket No. G–14587, are hereby amended so as to permit Petitioner, Southern Natural Gas Company, to transport and deliver to Southern Nitrogen Company a maximum of 16,750 Mcf of natural gas per day, of which 10,100 Mcf will be firm gas and 6,650 Mcf interruptible, in lieu of the presently authorized deliveries of 11,000 Mcf per day, of which 6,500 Mcf is firm gas and 4,500 Mcf interruptible.

(B) In all other respects, said orders shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TRUNKLINE GAS COMPANY, DOCKET NO. CP62–41; TEXAS EASTERN TRANSMISSION CORPORATION, DOCKET NO. CP62–120

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 25, 1962)

On August 17, 1961, as supplemented on September 25, 1961, Trunkline Gas Company (Trunkline) filed in Docket No. CP62–41, and on November 13, 1961, as supplemented on December 1, 1961, Texas Eastern Transmission Corporation (Texas Eastern) filed in Docket No. CP62–120, respectively, applications pursuant to Section 7(c) of the Natural Gas Act for certificates of public convenience and necessity authorizing the construction and operation of facilities to establish an interconnection between the pipelines of the Applicants in Hidalgo County, Texas, and the sale of natural gas through said facilities by Trunkline to Texas Eastern, all as more fully set forth in the applications, as supplemented.

Trunkline seeks authorization to construct and operate approximately 491 feet of 4-inch O.D. pipeline and a metering station to interconnect its facilities with those of Texas Eastern as aforesaid. Trunkline also seeks authorization to make a short-term sale of natural gas through said facilities to Texas Eastern on an interruptible basis up to a maximum daily contract quantity of 30,000 Mcf through the period ending July 1, 1962. Trunkline has an urgent need to commence the sale to Texas Eastern immediately in order to alleviate a temporary take-or-pay situation with respect to its gas purchase contracts. As of the end of the year 1961, Trunkline estimates that it will have incurred liability for payment for accumulated prepaid gas purchase volumes amounting to approximately 28,000,000 Mcf.

Texas Eastern seeks authorization to construct and operate a main line tap and related facilities on its 30-inch McAllen-Vidor pipeline in Hidalgo County, Texas, to receive the aforementioned short-term supply of gas from Trunkline. Texas Eastern will be able to use the gas in augmentation of its existing supplies, as an additional source for service to existing markets. This will enable Texas Eastern to conserve its long-term supply for future use.

The estimated cost of the facilties in Docket No. CP62–41 is $15,000, and in Docket No. CP62–120, $5,900. Both applicants will finance their respective facilities from funds on hand.

The subject sale of natural gas will be at a price of 15 cents per Mcf at 14.65 psia under Trunkline's Rate Schedule F–3.

Trunkline and Texas Eastern were granted temporary authorization in the subject dockets on October 19, 1961, and December 12, 1961, respectively.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 15, 1962, respecting the matters involved in and the issues presented by the applications herein. No petition to intervene or protest to the granting of the applications has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Trunkline Gas Company, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of April 29, 1949, in Docket No. G–882 (8 FPC 250).

(2) Applicant, Texas Eastern Transmission Corporation, a Delaware Corporation having its principal place of business in Houston, Texas, is a "natural-

gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of March 30, 1949, in Docket No. G–1089 (8 FPC 228).

(3) The facilities hereinbefore described, as more fully described in the applications, as supplemented, in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission and the construction and operation thereof and the proposed sale and transportation of natural gas are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) Applicants are able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natuarl Gas Act and the requirements, rules and regulations of the Commission thereunder.

(5) The construction and operation of the proposed facilities by Applicants and the proposed sale of natural gas by Trunkline are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(6) Public convenience and necessity require that the ceritificates issued hereinafter and the rights granted thereunder be conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (c) (4) and (e) of Section 157.20 of such Regulations.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Trunkline Gas Company, to construct and operate the proposed facilities and to sell and deliver a maximum of 30,000 Mcf of natural gas per day at 14.65 psia to Texas Eastern Transmission Corporation until July 1, 1962, as hereinbefore described, all as more fully described in the application, as supplemented, in Docket No. CP62–41, upon the terms and conditions of this order.

(B) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Texas Eastern Transmission Corporation, to construct and operate the proposed facilities in order to receive natural gas from Trunkline until July 1, 1962, as hereinbefore described, all as more fully described in the application, as supplemented, in Docket No. CP62–120, upon the terms and conditions of this order.

(C) The certificates issued by paragraphs (A) and (B) above and the rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (c) (4) and (e) of Sectior 157.20 of such Regulations.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L.J. O'Connor, Jr., and Charles R. Ross.

LONE STAR GAS COMPANY, DOCKET NO. G–8763

ORDER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND ACCEPTING SERVICE AGREEMENT FOR FILING

(Issued January 29, 1962)

On October 18, 1961, Lone Star Gas Company (Movant) filed a motion to amend the Commission's order issued December 4, 1956, in Docket No. G–8763

so as to enable Movant to sell and deliver additional volumes of natural gas to Natural Gas Pipeline Company of America (Natural).

In the December 4, 1956, order the Commission authorized Movant to construct and operate certain facilities and to sell and deliver an average of 80,000 Mcf of natural gas per day and up to a maximum of 100,000 Mcf of natural gas per day to Natural at a point in Stephens County, Oklahoma. Movant herein proposes to increase these authorized volumes to a daily average of 100,000 Mcf with a maximum of 125,000 Mcf per day.

Movant states that Natural has an immediate need for the additional gas and that because of the loss of certain markets involving power plant sales, Movant will have a total of 30,553 Mcf of gas per day available to help meet the proposed increased sales.

Concurrently with the filing of its motion, Movant filed a superseding service agreement, dated October 10, 1961, providing for the proposed increased sales to Natural.

No additional facilities are required to effectuate the subject proposal.

Due notice of the filing of the motion to amend and opportunity for hearing thereon has been given by publication in the Federal Register on December 28, 1961 (26 FR 12637). No protest or petition to intervene has been filed in this proceeding.

The Commission finds:

It is necessary and appropriate to carry out the provisions of the Natural Gas Act, and the public convenience and necessity require that the Commission's order issued December 4, 1956, in this proceeding be amended as hereinafter ordered.

The Commission orders:

(A) The Commission's order issued December 4, 1956, in Docket No. G–8763, is hereby amended so as to enable Movant, Lone Star Gas Company, to sell and deliver an average of 100,000 Mcf of natural gas per day and up to a maximum of 125,000 Mcf of natural gas per day to Natural Gas Pipeline Company of America in lieu of the 80,000 Mcf daily average and 100,000 Mcf daily maximum heretofore authorized in this proceeding.

(B) Movant's superseding service agreement, dated October 10, 1961, providing for the increased sales authorized in paragraph (A) above is hereby accepted for filing to become effective on the date this order issues.

(C) In all other respects, said order issued in this proceeding on December 4, 1956, shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

MIDWESTERN GAS TRANSMISSION COMPANY, DOCKET NOS. G–18313, G–18314, G–18315; MICHIGAN WISCONSIN PIPE LINE COMPANY, DOCKET NO. G–18316

ORDER DENYING MOTION FOR RECONSIDERATION

(Issued January 29, 1962)

On December 29, 1961, Michigan Gas and Electric Company (MG & E) filed a motion for reconsideration of the Commission's order accompanying Opinion No. 331, issued October 31, 1959, 22 FPC 775 in the above-entitled consolidated

proceeding.[1] MG & E's motion requests that the Commission "* * * reconsider the provisions of its order issued October 31, 1959, which imposed the full burden of the cost of the branch line upon the Upper Peninsula of Michigan, and pending such reconsideration extend the time for compliance with Paragraphs (Q) and (R) of said order". On January 16, 1962, Michigan Wisconsin Pipe Line Company (Mich. Wis.) filed an answer in opposition to the granting of MG & E's motion. We issued an order on January 5, 1962 *supra*, p. 4, in this proceeding extending the time for compliance by MG & E with ordering paragraphs (Q) and (R) of our order of October 31, 1959, pending further consideration of MG & E's motion.

After a thorough review of MG & E's motion, we have been unable to find therein any contentions in addition to those which MG & E has previously raised in its application for rehearing of the order accompanying Opinion No. 331, or in its briefs and arguments before the United States Court of Appeals for the District of Columbia Circuit or in MG & E's petition for writ of certiorari, filed August 30, 1961, in the Supreme Court of the United States. We denied MG & E's application for rehearing of the order accompanying Opinion No. 331 by our order issued December 29, 1959, 22 FPC 1157, in this proceeding. The order accompanying Opinion No. 331 was affirmed in *Michigan Gas and Electric Co.* v. *F.P.C.*, 290 F. 2d 374 (CADC), and MG & E's petition for certiorari was denied by the Supreme Court in *Michigan Gas and Electric Co.* v. *F.P.C.*, S. Ct. No. 368, on November 6, 1961, 368 U.S. 897.

MG & E's motion also refers to Opinion No. 345 issued June 28, 1961, in *Northern Natural Gas Company, et al.*, Docket Nos. G–20570, *et al.*, 25 FPC 1234. All that Opinion No. 345 stated in connection with construction of long laterals was that when Mich. Wis. proposes to construct laterals, to which its ten-cent formula is not considered applicable, it should devise a consistent formula to be used in consructing long laterals. In so holding, we did not refute our previous finding in Opinion No. 331, 22 FPC 775, at page 795, to the effect that:

> * * * providing for purchases by Michigan Gas under the ACQ–1 Rate Schedule and construction by it of the necessary Upper Peninsula facilities does not discriminate against that company.

When the Court upheld our order accompanying Opinion No. 331 and the Supreme Court denied certiorari, as hereinbefore indicated, MG & E's claims of undue discrimination were laid to rest and MG & E's motion raises no new questions of law or fact which have not already been carefully considered by the Commissions and duly reviewed by the courts.

The conditions in paragraphs (Q) and (R) of the order accompanying Opinion No. 331 required that MG & E construct the necessary facilities in the Upper Peninsula and file with the Commission proof of its having (1) obtained a contract with its principal customer and (2) secured the necessary State authorizations prior to the delivery by Mich. Wis. of gas to M G& E at Menominee, Michigan. The tenor of MG & E's motion is that unless the Commission modifies the conditions of the order accompanying Opinion No. 331, MG & E will be unable to provide service to the people of the Upper Peninsula. Furthermore, the prayer for relief specifically requested an extension of time for compliance with the aforementioned conditions pending only our reconsideration of MG & E's motion. Therefore, on the date of issuance of this order, Mich. Wis.' obligation to deliver and sell a maximum daily quantity of 37,200 Mcf of gas to MG & E at Menominee for serving the Upper Peninsula will be terminated.

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[1] On January 25, 1962, MG & E filed a "Supplement to Motion for Reconsideration" requesting that reconsideration be deferred until the Commission "* * * has made its decision on branch or lateral line formula in Docket No. RP60–9". We have considered the supplement but it does not alter our findings herein.

The Commission finds:

(1) The assignments of error and grounds for reconsideration stated in MG & E's motion for reconsideration set forth no new facts or principles of law which were not fully considered by the Commission when it adopted its order accompanying Opinion No. 331, 22 FPC 775 and its order denying rehearing issued December 29, 1959, 22 FPC 1157, or which have not already been reviewed by the courts as hereinbefore indicated, or which having now been considered warrant any change or modification in said orders.

(2) No request having been made by MG & E for an extension of time within which to comply with the conditions accompanying Opinion No. 331 under the original terms of that order, Mich. Wis.'s obligation to provide a maximum daily quantity of 37,200 Mcf of gas to MG & E at Menominee for Upper Peninsula service should be terminated as of the date of issuance of this order.

The Commission orders:

(A) The "Motion of Michigan Gas and Electric Company for Reconsideration of Requirements of Order Issued October 31, 1959 and Extension of Time for Compliance", filed December 29, 1961, is hereby denied.

(B) Mich. Wis.'s obligation to provide a maximum daily quantity of 37,200 Mcf of gas to MG & E at Menominee for Upper Peninsula service is hereby terminated as of the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

MISSISSIPPI RIVER TRANSMISSION CORPORATION, DOCKET No. CP62–76

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued January 29, 1962)

On September 25, 1961, Mississippi River Transmission Corporation (Applicant) filed in Docket No. CP62–76 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the transportation and sale of natural gas in interstate commerce for resale, all as more fully set forth in the application.

Applicant proposes to transport and sell natural gas on an interruptible basis to its two existing firm service (Rate Schedule CQ–1) customers, Laclede Gas Company (Laclede) and Illinois Power Company (Illinois). The proposed interruptible service would likewise be available to any additional customers whom Applicant is authorized to serve under Rate Schedule CQ–1 and who enter into an agreement with Applicant for service under said rate schedule.

Under an agreement among Laclede, Illinois, and Applicant dated April 22, 1960, Laclede and Illinois are entitled to purchase 63.75% and 11.25%, respectively, of the gas available to Applicant for purchase on any day from Trunkline Gas Company (Trunkline) under Trunkline's Rate Schedule R-1 (interruptible).

Proportionate quantities, i.e., quantities bearing the same relationship as the respective maximum daily contract quantities under Rate Schedule CQ–1, would be allocated to other firm service customers out of the remaining 25% not allocated to Laclede or Illinois. The initial rate at which Applicant proposes to sell such gas is 36.7 cents per Mcf, which rate is identical to that contained in Trunkline's Rate Schedule R–1 under which interruptible gas would be purchased by Applicant.

Applicant does not anticipate that substantial volumes of gas will be available for interruptible service at times when its customers desire additional gas. Applicant asserts, nevertheless, that to the extent that such gas is available from time to time, it could be of assistance to Applicant's customers in meeting the peak winter loads on their systems.

Uncertainty both as to the needs of the customers and the availability of gas when those needs occur makes it impracticable to prepare a realistic estimate of sales and revenues.

No additional facilities are proposed. Deliveries of interruptible gas to Laclede and Illinois will be made by means of the same facilities that are now used to make firm deliveries to said customers. Authorizations for additional facilities needed for deliveries to new customers will be requested in future proceedings as and when required, Applicant states.

Temporary authority to sell and deliver natural gas as proposed herein was granted Applicant on November 20, 1961. Concurrently with the granting of the temporary authorization, Original Sheet Nos. 9A, 9B, and 9C to Applicant's FPC Gas Tariff, Original Volume No. 1 were accepted for filing to become effective on the date of the initial delivery, subject to the conditions that Applicant pass on any refunds received from Trunkline in Docket No. RP60–6 and make appropriate rate reductions to reflect any reductions ordered in Trunkline's rates, and that such refunds and filings be satisfactory to the Commission.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 9, 1962, respecting the matters involved in and the issues presented by the application in this proceeding. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission under a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Mississippi River Transmission Corporation, a Delaware corporation having its principal place of business in St. Louis County, Missouri, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of November 29, 1960, in Docket No. CP60–95 (24 FPC 1020).

(2) The sale hereinbefore described, and as more fully described in the application in this proceedings will be made in interstate commerce, subject to the jurisdiction of the Commission, and such sale is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The sale of natural gas as proposed by Applicant is required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of such Regulations; and further, the certificate should be subject to the condition that Mississippi pass on to its customers any refunds received from its supplier, Trunkline Gas Company, in Docket No. RP60–6 and make appropriate rate reductions to reflect any reductions ordered in Trunkline's rates, and that said refunds and rate filings shall be satisfactory to the Commission.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued to Mississippi River Transmission Corporation authorizing the sale of natural gas as hereinbefore described, and as more fully described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of such Regulations; and further, the certificate is subject to the condition that Mississippi pass on to its customers any refunds received from its supplier, Trunkline Gas Company, in Docket No. RP60-6 and make appropriate rate reductions to reflect any reductions ordered in Trunkline's rates, and that said refunds and rate filings are satisfactory to the Commission.

Before Commissioners: Joseph C. Swidler, Chairman: Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

REVISION OF ANNUAL REPORT FORM PRESCRIBED FOR CLASS A AND CLASS B ELECTRIC UTILITIES, LICENSEES AND OTHERS SUBJECT TO THE FEDERAL POWER ACT, FPC FORM NO. 1, DOCKET NO. R-198

ORDER NO. 238-A

ORDER REVISING SCHEDULE PAGES OF ANNUAL REPORT FORM, FPC FORM NO. 1, FOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

(Issued January 26, 1962)*

On December 7, 1961, 26 FPC 798, the Commission issued its Order No. 238 (26 F.R. 11897, December 13, 1961), in this proceeding amending Section 141.1 of the Regulations under the Federal Power Act (18 CFR 141.1). Subsequent to the issuance of Order 238 examination of the Schedule Pages of the Report Form promulgated therein revealed the need for certain minor corrections of an editorial nature. These corrections are as set forth hereinafter. They have been incorporated in the printed blank report forms to be used in reporting for the year 1961 but they did not appear in the Schedule Pages annexed to Order 238 which was mailed to interested parties.

The Commission finds:

(1) It is necessary and appropriate for the purposes of the Federal Power Act that the Schedule Pages of FPC Form No. 1 as set forth in Appendix A to Order No. 238 be corrected to read as set forth hereinafter.

(2) In view of the facts set out above, good cause exists for this order to be effective as of the date of its issuance.

(3) The corrections herein adopted and approved are editorial in nature and so it is unnecessary to provide notice and opportunity for comment thereon pursuant to Section 4(a) of the Administrative Procedure Act.

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*Published in Federal Register, February 2, 1962 (27 F.R. 970).

The Commission acting pursuant to the Federal Power Act, as amended, particularly Sections 3(13), 4(a), (b), (c), 301(a), 302, 304, 309 and 311 thereof (16 U.S.C. 796(13), 797(a), (b), (c), 825(a), 825a, 825c, 825h, and 825j) *orders:*

(A) The following editorial corrections to the Schedule Pages of FPC Form No. 1 prescribed for electric utilities, licensees and others subject to the provisions of the Federal Power Act as set forth in Appendix A to Order No. 238 are hereby adopted and approved:

General Instructions—last line of instruction 4, change "I, II, III" to "iii, iv, and v."

List of Schedules—page II, change "Common Plant and Expenses and Other Common Expense and Statistical Data" to "Common Section"; page III, change page number for Construction Overheads-Electric from "428" to "427"; change page number for General Description of Construction Overhead Procedure from "427" to "428".

Page 104—item 2 add ")" after "1954".

Page 108—item 11, change "8" to "106".

Page 113—eliminate column (b) "Page No."

Page 204—account 144, item 1, change "reserve" to "accumulated provision"; item 2, delete "reserve".

Page 207—line 3, after "Residuals" add "and Extracted Products".

Page 214—heading for column (a), change "Description of other deferred debit" ot "Description of miscellaneous deferred debit."

Page 219—add "(omit cents)" after schedule heading.

Page 227—add "$" in columns (b), (c), (d), (e).

Page 420—add "(a), (b), (c), (d)" to column headings.

Page 427—place schedule "General description of construction overhead procedure" on page 428.

Page 428—place schedule "Construction overheads Electric" on bottom of page 427.

Page 433—add quotation marks at end of item 8.

(B) The aforesaid corrections to the Schedule Pages contained in FPC Form No. 1 are effective on the date of issuance of this order.

(C) The Secretary of the Commission shall cause prompt publication of this order in the Federal Register.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

REVISION OF ANNUAL REPORT FORM PRESCRIBED FOR CLASS A AND CLASS B NATURAL GAS COMPANIES SUBJECT TO THE NATURAL GAS ACT, FPC FORM NO. 2, DOCKET NO. R-201

ORDER NO. 239-A

ORDER REVISING SCHEDULE PAGES OF ANNUAL REPORT FORM, FPC FORM NO. 2, FOR NATURAL GAS COMPANIES

(Issued January 26, 1962)*

On December 7, 1961, 26 FPC 806, the Commission issued its Order No. 239 (26 F.R. 11900, December 13, 1961), in this proceeding amending Section 260.1 of the Regulations under the Natural Gas Act (18 CFR 260.1). Subsequent to the issuance of Order No. 239, examination of the Schedule Pages of the Report Form promulgated therein revealed the need for certain minor corrections of an editorial nature. These corrections are set forth hereinafter. They have been incorporated in the printed blank report forms to be used in reporting for the

*Published in Federal Register on February 2, 1962 (27 F.R. 970).

year 1961 but they did not appear in the Schedule Pages annexed to Order No. 239 which was mailed to interested parties.

The Commission finds:

(1) It is necessary and appropriate for the purposes of the Natural Gas Act that the Schedule Pages of FPC Form No. 2 as set forth in Appendix A to Order No. 239 be corrected to read as set forth hereinafter.

(2) In view of the facts set out above, good cause exists for this order to be effective as of the date of its issuance.

(3) The corrections herein adopted and approved are editorial in nature and so it is unnecessary to provide notice and opportunity for comment thereon pursuant to Section 4(a) of the Administrative Procedure Act.

The Commission acting pursuant to the Natural Gas Act, as amended, particularly Sections 8, 9, 10, and 16 (15 U.S.C. 717g, 717h, 717i, and 717o) *orders:*

(A) The following editorial corrections to the Schedule Pages of FPC Form No. 2 prescribed for natural gas companies subject to the provisions of the Natural Gas Act as set forth in Appendix A to Order No. 239 are hereby adopted and approved:

Cover—add bracket after "(Address of Principal Business Office at end of year)".

General Instructions—last line of instruction 4, change "I, II, III" to "i, ii, and iii."

Excerpts from the law—third line change "prescirbe" to "prescribe."

List of Schedules—page II change "Common Plant and Expenses and Other Common Expense and Statistical Date" to "Common Section"; Page III change page number for Construction Overheads—Gas from "544" to "543"; change page number for General Description of Construction Overhead Procedure from "543" to "544."

Page 104—item 2, add ")" after "1954."

Page 108—item 11, change "8" to "106."

Page 113—eliminate column (b) "Page No."

Page 204—account 144, item 1, change "reserve" to "accumulated provision"; item 2, delete "reserve."

Page 207—line 3 after "Residuals" add "and Extracted Products."

Page 214—heading for column (a) change "Description of other deferred debit" to "Description of miscellaneous deferred debit."

Page 219—add "(omit cents)" after schedule heading.

Page 227—add "$" in columns (b), (c), (d), (e).

Page 510—item 4, change page references "552 and 553" to "560 and 561."

Page 512—heading of schedule change "Abandoned" to "Abandonment of."

Page 513—heading for column (d) change to read "Accumulated Provision for Amortization (Account 115)".

Page 514—change last line to read "Total as above—line 12, columns (d) and (f)."

Page 534—item, top of page, change "page 30" to "page 212"; heading for column (c) change "797" to "795."

Page 539—line 2, delete "process."

Page 543—place schedule "General description of construction overhead procedure" on page 544.

Page 544—place schedule "Construction Overheads—Gas" on bottom of page 543.

(B) The aforesaid corrections to the Schedule Pages contained in FPC Form No. 2 are effective on the date of issuance of this order.

(C) The secretary of the Commission shall cause prompt publication of this order in the Federal Register.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. RP61-13

ORDER APPROVING SETTLEMENT, ACCEPTING TARIFF SHEETS, PRESCRIBING REFUNDS AND TERMINATING PROCEEDING

(Issued February 2, 1962)

On October 17, 1960, pursuant to the provisions of Section 4 of the Natural Gas Act, Transcontinental Gas Pipe Line Corporation (Transco) tendered for filing revised tariff sheets[1] proposing an annual increase, based on sales and transportation for the year ended July 31, 1960, as adjusted, of $11,786,567, or 7.0% over the rates established by order of the Commission issued October 19, 1960, in settlement of proceedings in Docket No. G-18783. Certain of the tariff sheets were withdrawn or corrected by filings made on November 7, 1960.[2] The increased rates were suspended by Commission order issued November 16, 1960, in the subject proceeding, and, pursuant to an appropriate motion by Transco, were made effective April 17, 1961, subject to refund.

The hearing in this matter commenced on October 3, 1961, pursuant to Commission order issued July 10, 1961. Upon completion of the direct presentation of Transco, the Staff and Interveners, and cross-examination of Transco's witnesses, the hearing was recessed to reconvene on December 4, 1961. Beginning on November 30, 1961, Transco, its customers, interested State commissions and the Staff participated in a series of conferences, culminating on December 19, 1961, in a general agreement and understanding concerning the settlement of matters in issue. On January 8, 1962, Transco introduced into the record as Exhibit No. 28 a Statement of Proposed Settlement, reflecting the agreement of the parties reached on December 19, 1961. No objection or protest to the proposed settlement has been made by any party to the proceeding.

On January 10, 1962, the presiding examiner certified to the Commission the Statement of Proposed Settlement together with the transcript of the proceeding held on January 8, 1962. The Statement of Proposed Settlement is attached

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[1] First Revised Sheet Nos. 17-0, 28-A.1 and 28-A.4; Second Revised Sheet Nos. 28-K.2, 28-X, 28-AA and 28-DD; Third Revised Sheet No. 28-R; Fifth Revised Sheet No. 27; Sixth Revised Sheet No. 28-P; Eighth Revised Sheet Nos. 17-B, 17-F and 26-B; Tenth Revised Sheet Nos. 9 and 28-I; and Eleventh Revised Sheet Nos. 5, 12, 16, 19 and 24 to Transco's FPC Gas Tariff Original Volume No. 1 and Eighth Revised Sheet No. 51 to Transco's FPC Gas Tariff Original Volume No. 2.

[2] First Revised Sheet No. 17-0 was withdrawn and another sheet substituted with a proposed effective date of August 12, 1960, which was accepted by the Commission by order issued November 18, 1960 in Docket No. G-18783. First Revised Sheet Nos. 28-A.1 and 28-A.4; Third Revised Sheet No. 28-R; Fifth Revised Sheet No. 27 and Sixth Revised Sheet No. 28-P were withdrawn for the reason that the rates approved by the Commission by order issued October 19, 1960 in Docket No. G-18783 were at the same level as those contained in these sheets. In order to correct the numbers of the tariff sheets filed October 17, 1960 to reflect the numbers subsequently employed on the tariff sheets filed to make the settlement rates in Docket No. G-18783 effective November 18, 1959 Transco filed the following new tariff sheets identical to those filed on October 17, 1960, except for the correction of the sheet numbers: Third Revised Sheet Nos. 28-K.2; 28-X, 28-AA and 28-DD; Ninth Revised Sheet Nos. 17-B, 17-F and 26-B; Eleventh Revised Sheet Nos. 9 and 28-I; and Twelfth Revised Sheet Nos. 5, 12, 16, 19 and 24 to Transco's FPC Gas Tariff Original Volume No. 1 and Ninth Revised Sheet No. 51 to Transco's FPC Tariff Original Volume No. 2.

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hereto as Exhibit A, and made a part hereof.[3] The proposed settlement would establish rates and charges to be effective as of January 1, 1962. Under those rates and charges Transco will realize an increase in its revenues in the amount of $7,844,046, based on sales for the 12 months ended December 31, 1960, as adjusted, in lieu of the requested increase of $12,472,222[4] under the rates and charges which became effective subject to refund on April 17, 1961.

Pursuant to the terms of the proposed settlement, and subject to approval of the settlement by the Commission, Transco filed with the Commission on January 9, 1962, revised and original tariff sheets,[5] copies of which are part of the settlement agreement (Appendix A thereto not here attached as noted above), to become effective January 1, 1962, superseding the rates presently effective, and among other things providing for new optional general service rates.[6] The rates to be made effective under the designated tariff sheets will provide Transco with jurisdictional revenues of $183,830,971, and when added to non-jurisdictional revenues of $1,736,927, will provide system revenues of $185,567,898.

Under the terms of the proposed settlement, Transco also filed on January 9, 1962 tariff sheets to simplify its tariff with respect to storage service rate schedules so as to establish one rate schedule for such service, Rate Schedule GSS.[7]

The proposed settlement provides for immediate refunds for the period April 17, 1961 through December 31, 1961 in an amount equal to the difference between the revenues collected under the rates which became effective April 17, 1961, and the revenues computed at the rates set out in the tariff sheets tendered for filing by Transco on January 9, 1962, together with interest thereon at the rate of 7 percent per annum from the date of payment to Transco until refunded. In addition, Transco will refund, applicable to the same period, in the manner set out in Article III (B) of the proposed agreement, an amount based upon the difference between the actual average cost per Mcf of purchased gas under regular and other contracts during the period and the 17.41¢ per Mcf representing the average cost of purchased gas under regular and other contracts included in the cost of service for settlement purposes to derive rates and charges to be effective from and after January 1, 1962, plus interest thereon at the rate of 7 percent per annum from the date of payment to Transco until refunded.

The proposed settlement also provides for passing through by Transco to its customers of refunds received by Transco from its suppliers and for reduction in rates to be made by Transco to reflect the reductions, if any, in the rates of its suppliers. The methods to be used by Transco in determining the refunds to its customers and in computing the reductions in its rates are set forth in considerable detail in Articles III, IV and V of the proposed settlement. Such refunds and rate reductions will be made to reflect Transco's

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[3] Appendix A to the proposed settlement agreement is comprised of copies of tariff sheets to be filed pursuant to that agreement. That Appendix A is not reproduced in the copy of the settlement agreement attached hereto.

[4] Based upon 12 months ending December 31, 1960, as adjusted, as compared with $11,786,567 filed increase based upon the year ended July 31, 1960 as adjusted.

[5] Sheet Nos.: Fourth Revised Nos. 28–K.2, 28–AA and 28–DD; Tenth Revised Nos. 17–F and 26–B; Eleventh Revised No. 17–B, Twelfth Revised Nos. 9 and 28–I, Thirteenth Revised Nos. 16, 19, and 24; Fourteenth Revised Nos. 5 and 12 to its FPC Gas Tariff Original Volume No. 1 and Tenth Revised Sheet No. 51 to its FPC Gas Tariff Original Volume No. 2.

[6] Original Sheet Nos. 26–F through 26–T. Original Sheet Nos. 45–A and 45–B, and First Revised Sheet No. 45 to its FPC Gas Tariff Original Volume No. 1.

[7] Sheet Nos.: Original 17–0.1; First Revised 17–H, 17–K, 17–P, 55–U, 55–V, 55–X.3, 55–W, 55–X.1, 55–X.2; Second Revised 17–I, 17–J, 17–L, 17–M, 17–N and 17.0.

reduced cost of purchased gas resulting from its suppliers' pending proceedings under Sections 4, 5, or 7 of the Natural Gas Act.

Refunds as computed under the proposed settlement will be made by Transco to its customers within 60 days after it receives a refund from any supplier. Similarly, any rate reductions to be reflected by Transco in its rates pursuant to the methods set forth in the proposed settlement, will be filed by Transco within 60 days of the effective date of the supplier's reduced rate, to be effective as of the same date that the supplier's reduced rates are applied in its billings for current deliveries to Transco. No rate reductions are to be made by Transco, however, until the aggregate of its suppliers' reductions exceeds $400,000 on an annual basis.

Transco also agrees that it will not file an increase in rates with the Commission prior to January 1, 1963 (to be effective, after suspension, not earlier than July 1, 1963), unless (1) new taxes or increases in existing tax rates which must be borne by Transco equal or exceed an annual rate of $400,000, or (2) as a result of governmental action (legislative or administrative) permitting Transco's suppliers in Texas Railroad Commission Districts 2, 3 and 4 to charge more than the contract prices, such increases in gas, offset as provided in Article VIII, equal or exceed an annual rate of $400,000.

We have reviewed all of the documents and data submitted in support of the proposed settlement, including the cost of service data utilized for such purposes, and such review indicates that the settlement of this proceeding on the basis of the proposed settlement agreement is in the public interest.

The Commission finds:

(1) The increased rates and charges contained in Transco's proposed revised tariff sheets tendered for filing on October 17, 1960, modified and corrected by withdrawals and filings on November 7, 1960 in this docket have not been shown to be just and reasonable or otherwise lawful under the terms and provisions of the Natural Gas Act and should be disallowed and denied as hereinafter provided and ordered.

(2) The proposed settlement of this proceeding upon the basis of the settlement agreement received in evidence in this proceeding, is in the public interest and appropriate to carry out the provisions of the Natural Gas Act, and such settlement should be approved, and be made effective as hereinafter provided.

(3) Good cause has been shown that the 30 day notice requirement of the Natural Gas Act be waived with respect to the original and revised tariff sheets listed in Article II, Paragraphs (A) and (B) of the Settlement, and filed by Transco on January 9, 1962, and that such tariff sheets be permitted to become effective as hereinafter ordered. Good cause has been shown also to accept without further investigation the tariff sheets listed in Paragraph (C) of Article II of the agreement.

The Commission orders:

(A) The increased rates and charges proposed by Transco in its filing of October 17, 1960, and its filing of November 7, 1960, and referred to in paragraph (1) above, hereby are disallowed.

(B) The settlement submitted by Transco and received in evidence in this proceeding, and the rates and charges set forth therein are hereby approved and made effective, subject to the terms and conditions of this order.

(C) The requirements of Part 154 of the Commission's Regulations under the Natural Gas Act hereby are waived to the extent necessary to permit the tariff sheets listed in Article II of the agreement to be effective, and such tariff sheets, filed by Transco on January 9, 1962 and listed in Article II (A) and (B)

of the settlement are made effective as of January 1, 1962, and the tariff sheets listed in Paragraph (C) thereof are made effective as of the date shown opposite each listed tariff sheet.

(D) Transco shall make refunds to its jurisdictional customers under Article III of the settlement proposal within 15 days after this order has become final and non-appealable.

(E) In the event Transco receives any refunds from any supplier as a result of any pending proceeding under Section 4 or 7 of the Natural Gas Act involving such supplier, and in the event any supplier reduces its rates as a result of any pending proceeding under Section 4, 5 or 7 of the Natural Gas Act, Transco shall in turn refund such amounts to its customers and reduce its rates in accordance with Articles IV, V and VI of the settlement and within the time provided in those articles.

(F) Within 15 days after making the refunds as provided by paragraphs (D) and (E) above, Transco shall report to the Commission, in writing and under oath the amount of the refund made to each of its customers, showing separately the amount of principal and interest so paid, and shall serve a copy of such report upon each of the customers receiving a refund. Concurrently therewith Transco shall file with the Commission releases from its customers showing receipt of the principal and interest.

(G) Upon full compliance by Transco with all the terms and conditions of this order and acceptance of the filings made by it, this proceeding shall be considered terminated.

(H) In issuing this order, the Commission's action is not to be construed as a concurrence with the cost of service determinations, allocation methods and rate design principles used in arriving at rates and charges for future sales, or in computing the amount of refunds agreed upon in the settlement agreement, and neither the Commission, its Staff, or other parties to the proceedings are to be prejudiced or bound thereby in future proceedings.

(I) This order is without prejudice to any findings or orders which have been or may hereafter be made by the Commission and is without prejudice to any claims or contentions which may be made by the Commission, Transco, the Commission staff, or any other party affected by this order, in any other proceeding now pending or hereafter instituted by or against Transco or any other companies, persons or parties affected by this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

DUKE POWER COMPANY, DOCKET NO. E-7018

ORDER AUTHORIZING THE ISSUANCE OF FIRST AND REFUNDING MORTGAGE BONDS

(Issued February 5, 1962)

Duke Power Company (Applicant), a corporation organized under the laws of the State of New Jersey and doing business in the States of North Carolina and South Carolina, with its principal place of business at Charlotte, North Carolina, filed an application on December 27, 1961, as amended January 16, 1962, for authorization, pursuant to Section 204 of the Federal Power Act, to issue and sell at competitive bidding $50,000,000 principal amount of First and Refunding Mortgage Bonds, Series due 1992.

Applicant proposes to issue the Bonds under its Indenture of First and Refunding Mortgage, between Applicant and Guaranty Trust Company of New

York (now Morgan Guaranty Trust Company of New York) and dated as of December 1, 1927, as heretofore supplemented and as to be further supplemented by a proposed, new Supplemental Indenture to be dated as of February 1, 1962.

Applicant proposes, on or about February 7, 1962, to invite sealed, written bids for the purchase of the proposed Bonds by newspaper publication and by distribution of a Form of Proposal, together with a statement of terms and conditions relating thereto and a form of purchase contract.

Each bid, whether made by a single bidder or a group of bidders, must be for the purchase of all of the Bonds, and must be in writing on the Form of Proposal provided by the Applicant. Each bid must specify: (1) the coupon rate to be borne by the Bonds, which rate shall be a multiple of ⅛th of 1%; (2) the price exclusive of accrued interest to be paid to Applicant for the Bonds, which price shall be expressed as a percentage of the principal amount of the Bonds and shall not be less than 98½% thereof; and, (3) that Applicant shall be paid the amount of the accrued interest on the Bonds from February 1, 1962 to the date of payment therefor and delivery thereof. Each bid must be accompanied by a certified or bank cashier's check or checks in the aggregate amount of $2,500,000.

Unless postponed, all bids for the purchase of the proposed Bonds must be received by Applicant before 11:00 a.m., Eastern Standard Time, on February 20, 1962, at Room 2322, No. 15 Broad Street, New York 5, New York. Unless Applicant rejects all bids for the proposed issuance of Bonds (which it reserves the right to do) or excludes a bid or bids for reasons specified in the statement of terms and conditions, it will accept the bid which provides it with the lowest annual cost of money.

The net proceeds to be obtained from the proposed issuance of Bonds will be used to finance, in part, Applicant's current construction program, including reimbursement, in whole or in part, of its treasury for expenditures heretofore made and to be made by it for such purpose between September 1, 1961 and February 28, 1962 (the date on which it is anticipated that the proceeds of such new securities will be available to the Applicant), and also including the payment of short-term notes issued under Section 204(e) of the Federal Power Act. Applicant estimates it will spend $53,036,000 on its 1962 construction program—of which $15,766,000 will be spent on the new Cowans Ford hydroelectric station to be completed in 1963; $1,300,000, on the first unit (350,000 kw) at the new Marshall steam-electric station, to be completed in 1965; $873,000, on other generating plant additions and changes; $7,786,000, on transmission lines and substations; and $27,311,000, on distribution lines, substations and general facilities.

Written notice of the application has been given to the North Carolina Utilities Commission and the South Carolina Public Service Commission, and to the Governor of each of those States. Notice has also been given by publication in the Federal Register on January 9, 1962 (27 F.R. 244), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before January 22, 1962 with the Federal Power Commission, Washington 25, D.C. No protest, petition or request to be heard in opposition to the granting of the application has been received.

The North Carolina Utilities Commission, by order issued January 11, 1962, and the South Carolina Public Service Commission, by order dated January 3, 1962, approved the proposed issuance and sale of Bonds in the manner and for the purposes set forth above.

The Commission finds:

(1) Applicant, a corporation, is a public utility within the meaning of Section 204 of the Federal Power Act, subject to the jurisdiction of the Commission, as heretofore described and set forth in the Commission's order issued December 29, 1955, *Duke Power Company*, Docket No. E–6652 (14 FPC 1163).

(2) The proposed issuance and sale of Bonds, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204(f) of the Act; and the proposed issuance of securities is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

(5) The period of public notice given in this matter is reasonable.

The Commission orders:

(A) The proposed issuance and sale of Bonds, upon the terms and conditions and for the purposes specified in the application, as described above, are hereby authorized, subject to the provisions of this order.

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations;

(ii) The Commission, by a further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

(C) This authorization shall expire unless the transaction hereby authorized is consummated within 90 days from the date of issuance of this order.

(D) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(E) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States with respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

HUMBLE OIL & REFINING COMPANY, DOCKET NO. CI62-627

ORDER ON MOTION TO DISMISS ORDER TO SHOW CAUSE AND TERMINATE PROCEEDINGS

(Issued February 5, 1962)

On January 16, 1962, Humble Oil & Refining Company (Humble) filed a response to the Commission's order issued December 13, 1961, 26 FPC 854, which required Humble to show cause why it should not file an application pursuant to Section 7(c) of the Natural Gas Act to acquire by stock ownership the facilities of Olin Gas Transmission Corporation.

Humble, by its response, asks in the alternative, that (1) the Commission terminate its show cause proceeding and issue an order declaring that Section 7(c) does not require that Humble obtain a certificate of public convenience and necessity before it consummates the acquisition of the stock of Olin Gas Transmission; (2) the Commission issue forthwith [1] a certificate of public convenience and necessity authorizing it to acquire all the outstanding capital stock of Olin Gas Transmission, if such a certificate is deemed required by Section 7(c); (3) that, if the relief requested under (1) and (2) is denied, the Commission advance the date of hearing to February 19, 1962.

Humble's motion to terminate the proceeding and dismiss the Commission's order to show cause is predicated on the assumption that the acquisition of all the outstanding stock of Olin Gas Transmission by Humble does not constitute an "acquisition of facilities" within the meaning of Section 7(c) of the Natural Gas Act. However, the order to show cause does not preclude Humble from asserting this contention in course of the proceedings. Humble may renew its motion after presenting evidence in support of its application.

The instant order is not to be construed in any way as a determination by the Commission, at this time, of the legal question of jurisdiction raised by Humble to the Commission's order to show cause.

The Commission finds:

(1) There are sufficient grounds for going forward with the proceedings instituted by the order to show cause.

(2) The motion for termination of the proceedings should be denied, without prejudice to its renewal at a subsequent stage of the case.

(3) The motion for issuance of a certificate after an abridged hearing should be denied on the ground that the Commission would not be in a position to make a determination of the issues which would be involved in certification without a record.

(4) It is necessary and appropriate in the public interest that the date of hearing be advanced to a date earlier than set in the Commission's order of December 13, 1961.

The Commission orders:

(A) The motion of Humble Oil and Refining Company to dismiss the order to show cause contained in its response to the Commission's order of December 13, 1961, is hereby denied, without prejudice.

(B) For the reasons stated above, the motion requesting the issuance of a certificate of public convenience and necessity after an abridged hearing is hereby denied.

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[1] I.e., after an abridged hearing.

(C) The public hearing in this proceeding, heretofore set for March 27, 1962, is advanced to March 2, 1962, at the same hour and place provided in the Commission's order of December 13, 1961.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TEXAS EASTERN TRANSMISSION CORPORATION AND TEXAS GAS TRANSMISSION CORPORATION, DOCKET NO. CP62-6

ORDER PERMITTING INTERVENTION AND GRANTING LIMITED CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY UPON MOTION FOR RECONSIDERATION

(Issued February 5, 1962)

This matter is before us upon a joint motion filed on January 11, 1962, by Texas Eastern Transmission Corporation (Texas Eastern) and Texas Gas Transmission Corporation (Texas Gas) for reconsideration of our order issued December 14, 1961, 26 FPC 876, remanding the above-styled proceeding to the presiding examiner for formal hearing. Ohio Valley Gas Corporation (Ohio Valley), whose interest in the proceeding is made obvious by facts hereinafter set forth, on January 5, 1962, filed a petition to intervene in the proceeding. In its petition to intervene Ohio Valley also requests reconsideration of our order issued December 14, 1962.

This proceeding involves a joint application, as supplemented, filed by Texas Eastern and Texas Gas for a certificate of public convenience and necessity pursuant to Section 7(c) of the Natural Gas Act authorizing Texas Gas to sell up to 6,000 Mcf of natural gas per day to Ohio Valley for resale in Connersville, Indiana, and environs, and (b) the delivery, for a temporary period, of natural gas by Texas Eastern to Ohio Valley for the account of Texas Gas in exchange for the delivery of equivalent volumes of gas by Texas Gas to Texas Eastern.

Texas Eastern also requests permission to abandon pursuant to Section 7(b) of the Natural Gas Act the sale of natural gas to Ohio Valley. The abandonment would be coincident with the commencement of the sale by Texas Gas to Ohio Valley.

Upon the termination of the proposed temporary exchange of gas, Texas Eastern also requests permission to abandon the meter facilities presently used in connection with its sale to Ohio Valley. Upon such termination Texas Gas would render service directly to Ohio Valley from its own pipeline system.

The proposed exchange of natural gas would be made pursuant to an exchange agreement dated June 14, 1961. This agreement, filed on July 16, 1961, by Texas Eastern as its proposed Rate Schedule X-46, is for a period of three years from the date of first delivery and provides that Texas Eastern shall deliver Ohio Valley's gas requirements for Connersville at the existing delivery point in Ripley County, Indiana, for the account of Texas Gas. Texas Gas will in turn deliver equivalent volumes to Texas Eastern at an existing interconnection between the two pipeline systems near Lebanon, Ohio.

Under a tripartite agreement entered into on June 14, 1961, Ohio Valley agreed, within three years, to construct a 15-mile transmission line extending from Texas Gas' facilities in Dearborn County, Indiana, to the terminus of its existing 26-mile pipeline extending from Connersville to Texas Eastern's main line in Ripley County, Indiana. Texas Gas agreed to include facilities in its next system expansion application to provide 6,000 Mcf per day of firm capacity to serve Ohio Valley.

After due notice, an abridged hearing was held on November 30, 1961, on the joint application. When the matter came before us, we issued an order, dated December 14, 1961, remanding the proceeding to the presiding examiner for formal hearing with respect to (1) whether or not the proposal may be discriminatory among customers served by Texas Eastern; and (2) whether or not the public convenience and necessity required approval of the proposal.[1]

It is the order of remand issued December 14, 1961, we are asked to reconsider. We grant the motion for reconsideration. Further, we permit Ohio Valley to intervene in the proceeding.

From the allegations made, under oath, in the joint motion for reconsideration and the petition to intervene it appears that Ohio Valley, for the past several years, has suffered such substantial losses from its Connersville operations that future service in such community at reasonable rates is jeopardized. It further appears that if Ohio Valley obtains its gas supply from Texas Gas rather than Texas Eastern, due to the differential in rates of the two companies, substantial savings in purchased gas cost would be achieved which would redound to the benefit of ultimate consumers.

By letter dated January 8, 1962, to Texas Eastern and Texas Gas, Ohio Valley has agreed to construct its proposed pipeline to take gas directly from Texas Gas within 18 months of receipt of approval of the proposed arrangement by this Commission. Moreover by letter to the Commission dated January 19, 1962, Ohio Valley has agreed "to immediately start the necessary steps for building the pipeline connecting its facilities at Connersville, Indiana, with the pipeline of Texas Gas and to vigorously push construction of said line and, if possible, complete the same before the 1962–1963 heating season."

Troubled though we are by the problem of possible duplication of the pipeline facilities of two natural-gas companies subject to our jurisdiction to render service to a single distribution company, we are of the opinion that the benefits of the proposal before us to ultimate consumers may more than offset the detriments of such proposal. Taking all equitable factors into consideration we feel that we can adequately protect the public interest through our power to condition the certificate we will issue to Texas Gas to sell natural gas to Ohio Valley.

We will grant a certificate of public convenience and necessity to Texas Gas authorizing it to sell natural gas to Ohio Valley, delivery thereof to be made by Texas Eastern, for a maximum period of 18 months from the date of issuance of this order. In the event, however, Ohio Valley has constructed and is ready to place in operation the facilities necessary to take gas directly from Texas Gas within the 18-months period, then Texas Gas may file for appropriate authority to continue the sale directly from its own pipeline. We will also authorize the exchange of gas between Texas Gas and Texas Eastern for a maximum period of 18 months. In the event, however, that Ohio Valley has not constructed within 18 months the pipeline facilities necessary to enable it to take gas directly from Texas Gas, then Ohio Valley, if it desires to continue its Connersville natural gas operations, shall revert to the *status quo* existing as of this time, and shall thereafter be a customer of Texas Eastern.

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[1] After issuance of the order of remand, a joint petition for leave to intervene was filed on January 2, 1962, by The Manufacturers Light and Heat Company and The Ohio Fuel Gas Company. By letter dated January 16, 1962, these parties indicated that the filing of the joint petition "should not be interpreted as evidence of their belief that a formal hearing is necessary. It is merely a request to participate in a hearing if a hearing is held."

In view of the action we take by this order we will consider the joint petition for leave to intervene to be mooted.

To carry out the intent of the foregoing we shall defer action on the joint application insofar as it relates to the abandonment by Texas Eastern of facilities by means of which it presently renders service to Ohio Valley.

The Commission finds:

(1) The joint motion of Texas Eastern Transmission Corporation and Texas Gas Transmission Corporation filed on January 11, 1962, should be granted as being appropriate in the public interest.

(2) It is appropriate in the public interest to permit Ohio Valley Gas Corporation to intervene in this proceeding.

(3) Texas Eastern Transmission Corporation, a Delaware corporation having its principal place of business in Shreveport, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission by its order of October 10, 1947, Docket No. G–880, 6 F.P.C. 148.

(4) Texas Gas Transmission Corporation, a Delaware corporation having its principal place of business in Owensboro, Kentucky, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order issued March 30, 1949, Docket No. G–859, 8 F.P.C. 190.

(5) The proposed sale and delivery and the proposed exchange of natural gas, as authorized herein, are to be made in interstate commerce and are subject to the jurisdiction of the Commission, and such proposed sale and delivery and such proposed exchange and delivery of natural gas are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(6) The proposed sale and delivery and the proposed exchange and delivery of natural gas by Texas Eastern Transmission Corporation and Texas Gas Transmission Corporation, as authorized herein, are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(7) The sale of natural gas and the facilities proposed to be abandoned by Texas Eastern Transmission Corporation, fully described in the joint application, as supplemented, are subject to the jurisdiction of the Commission and the abandonment of such sale and of such facilities by Texas Eastern are subject to the requirements of subsection (b) of Section 7 of the Natural Gas Act.

(8) The public interest requires that action on the proposed abandonment of the facilities utilized by Texas Eastern in making delivery of natural gas to Ohio Valley Gas Corporation should be deferred.

(9) Upon acceptance of the terms and conditions of this order, Texas Eastern and Texas Gas will have demonstrated that they are able and willing properly to do the acts and perform the service proposed as authorized and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(10) Public convenience requires that all applicable provisions of the Commission's Regulations under the Natural Gas Act, and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3) and (e) of Section 157.20 of such Regulations, should attach to the certificate hereinafter issued and to the exercise of the rights granted thereunder and that the proposed sale and exchange of natural gas authorized shall commence within six months from the date on which this order issues.

(11) The exchange agreement between Texas Eastern and Texas Gas dated June 14, 1961, should be accepted for filing as Texas Eastern's FPC Gas Rate Schedule X–46 to become effective on the date of issuance of this order and to remain effective for a period of 18 months therefrom.

The Commission orders:

(A) The joint motion filed by Texas Eastern and Texas Gas on January 11, 1962, be and it is hereby granted.

(B) Ohio Valley be and it is hereby permitted to become an intervener and party to this proceeding.

(C) A certificate of public convenience and necessity be and the same is hereby issued authorizing: (a) Texas Gas to sell natural gas to Ohio Valley for a period of 18 months from the date of issuance of this order, (b) the delivery of natural gas by Texas Eastern to Ohio Valley for the account of Texas Gas for a period of 18 months from the date of issuance of this order, and (c) the exchange of natural gas between Texas Eastern and Texas Gas for a period of 18 months from the date of issuance of this order, all upon the terms and conditions of this order.

(D) All applicable provisions of the Commission's Regulations under the Natural Gas Act, and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3) and (e) of Section 157.20 of such Regulations, shall attach to the issuance of the certificate granted in Paragraph (A) hereof and to the exercise of the rights granted thereunder.

(E) The sale and delivery of natural gas and the exchange and delivery of natural gas as authorized in Paragraph (A) hereof shall commence within six months from the date this order issues.

(F) The exchange agreement between Texas Eastern and Texas Gas dated June 14, 1961, be accepted for filing and made effective as Texas Eastern's FPC Gas Rate Schedule X–46 as of the date this order issues, and remain effective for a period of 18 months therefrom.

(G) Action on the joint application insofar as it relates to the abandonment by Texas Eastern of facilities by means of which service is rendered to Ohio Valley be deferred.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

COLORADO INTERSTATE GAS COMPANY, DOCKET NO. CP62–100

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 6, 1962)

On October 19, 1961, Colorado Interstate Gas Company (Applicant), filed in Docket No. CP62–100 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of a meter station and appurtenant facilities and the sale of natural gas through said facilities to Plateau Natural Gas Company (Plateau) for resale in Franktown, Douglas County, Colorado, all as more fully set forth in the application.

The proposed facilities will be constructed on Applicant's Amarillo-to-Denver pipeline at a point near Franktown, Douglas County, Colorado. The cost is estimated to be $4,620, which will be financed from funds on hand.

Service will be rendered by Applicant to Plateau under Applicant's existing FPC Gas Rate Schedule SG–1 (First Revised Volume No. 1, Original Sheet Nos. 7 and 8 of Applicant's FPC Gas Tariff).

Estimated annual and peak day requirements for each of the first three years of operation are 5,557 and 56 Mcf, respectively, at 14.73 psia.

There will be no increase in Plateau's contract demand.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 30, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Colorado Interstate Gas Company, a Delaware corporation having its principal place of business in Colorado Springs, Colorado, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of June 5, 1945, in Docket No. G–294 (4 FPC 936).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof and the related proposed sale of natural gas are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities and the proposed sale of natural gas by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of said Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Colorado Interstate Gas Company, to construct and operate the proposed facilities and to transport and sell natural gas to Plateau Natural Gas Company, as hereinbefore described and as more fully described in the application herein, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The construction of the facilities authorized in paragraph (A) above shall be completed and said facilities placed in actual operation within one year from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP62-37

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 6, 1962)

On August 15, 1961, Northern Natural Gas Company (Applicant) filed in Docket No. CP62-37 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the calendar year 1962 at a total cost not to exceed $3,000,000, with no single project to exceed a cost of $500,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

The proposed facilities will be financed from funds on hand and from funds generated through operations.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 30, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Northern Natural Gas Company, a Delaware corporation, having its principal place of business in Omaha, Nebraska, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G-280 (3 FPC 967).

(2) The facilities hereinbefore described, as more fully described in the application herein, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing pipeline system, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of facilities to take natural gas purchased from producers thereof during the calendar year 1962 as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the costs of the facilities so

constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(6) The authorization granted herein should be limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed hereunder should be limited to $3,000,000, with no single project to exceed a cost of $500,000.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (a) and (e) of Section 157.20 of said Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Northern Natural Gas Company to construct during the calender year 1962 the proposed facilities hereinbefore described (more fully described in the application filed in this proceeding) and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Northern Natural Gas Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicants compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(C) Applicant shall submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the cost of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for the facilities constructed hereunder are hereby limited to $3,000,000, with no single project to exceed a cost of $500,000.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP62-128

FINDINGS AND ORDER PERMITTING AND APPROVING ABANDONMENT OF FACILITIES

(Issued February 6, 1962)

On November 22, 1961, as supplemented on December 1, 1961, Northern Natural Gas Company (Applicant) filed in Docket No. CP62-128 an application pursuant

to Section 7(b) of the Natural Gas Act for permission and approval to abandon its Otis, Kansas, Compressor Station, all as more fully set forth in the application, as supplemented.

This 500 H.P. station is no longer used or needed due to the depletion of the Otis gas field in Rush and Barton Counties, Kansas, the source of gas formerly compressed by the Otis Station. The two 250 H.P. units comprising the station are obsolete and can not be used efficiently on Applicant's system in other locations.

The Otis compressor facilities were certificated by the Commission in Docket No. G–667 on May 28, 1946.

The original cost of the subject facilities was $101,911, which has been depreciated by $90,311. Applicant proposes to sell the compressor units for $25,000 and dispose of the remaining facilities as junk.

No abandonment of service will result from the abandonment of the subject facilities.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 30, 1962, respecting the matters involved in and the issues presented by the application, as supplemented herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Northern Natural Gas Company, a Delaware Corporation having its principal place of business in Omaha, Nebraska, is a "natural-gas company" as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G–280 (3 FPC 967).

(2) The facilities to be abandoned, as hereinbefore described and as more fully described in the application, as supplemented, in this proceeding, are subject to the jurisdiction of the Commission, and abandonment of such facilities is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(3) Such abandonment by Applicant, as hereinbefore described, is permitted by the public convenience and necessity, and an order permitting and approving same should be issued as hereinafter ordered.

(4) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Permission for and approval of the abandonment by Applicant, Northern Natural Gas Company, of the facilities hereinbefore described, all as more fully described in the application, as supplemented, in this proceeding, be and the same is hereby granted.

(B) Applicant shall advise the Commission of the date of the abandonment of said facilities within ten days of the date thereof.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. G-11980

OPINION AND ORDER DETERMINING PRINCIPLES AND METHODS OF ALLOCATION AND RELATED ISSUES

(Issued February 6, 1962)*

Syllabus

1. Since Tennessee operates a fully integrated transmission system providing essentially same type of pipeline service in all zones, with zone boundaries which do not correspond to any actual divisions in system operations or service, Commission finds it obviously impossible to identify the portion of its main-line facilities which was installed or is used specifically for benefit of any individual customer. P. 208.
2. Commission adopts Mcf-mile method (with modifications) for allocation of Tennessee's system-wide transmission costs between existing zones to be applicable for future—unless or until demonstrated that a change is required. Pp. 206; 215.
3. Any allocation method for Tennessee's system should meet following basic requirements: (1) Assign fair share of total system cost of service to each zone; (2) be practical and not so complex as to require long tedious studies, etc., but be one that can be expeditiously applied to facts quickly ascertainable; and (3) results reached should make sense. P. 208.
4. Commission policy of using system-wide average of mainline transmission costs of integrated pipeline as foundation for allocation of costs to zones or classes of customers, results in administrative simplicity; but more importantly the sharing of system costs on system-wide basis is a fairer and more rational concept of allocation than any attempt to guess what it might cost to serve each individual customer separately. P. 208.
5. As between two allocation procedures, both economically defensible, that one should be preferred which minimizes the differential in zone rates; but differences in cost in system as large as Tennessee's should not be ignored since use of average cost method without zone differentials would, in circumstances of this case, result in undue discrimination. P. 209.
6. In determining extent to which modification of average cost method is required, Commission considers load factor, load density and distance of transmission, of which, the latter has most constant and predictable relation to cost. P. 209.
7. Where zones of a pipeline system have no extreme variations in load factors or load density, density factor can, by Mcf-mile method, be applied directly to system-wide costs to provide allocation giving reasonable effect to increase in cost of transmission in each successive zone without disregarding that facilities in each zone are part of integrated system. P. 209.
8. Commission *rejects* zone-by-zone method for Tennessee's system; finding there is no objective formula for determining "actual cost" of serving one or more customers from integrated pipeline, and noting that segregation of facilities contemplated by zone-by-zone method has never been approved as a basis of allocation of transmission costs of integrated system. P. 210.
9. A condition which was part of order issued on limited record in certificate proceeding could not, in the circumstances, predetermine method of allocation to be adopted in future rate case. P. 211.

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*Designated Commission Opinion No. 352. Initial decision appears on p. 220. Rehearing denied by order issued April 5, 1962, 27 FPC 668. Petition for Review dismissed, *The Manufacturers Light & Heat Company* v. *F.P.C.* (CADC No. 17064). [Unreported]

10. City-gate service found only characteristic of New England zone requiring departure from Mcf-mile method of allocation; since facilities required for such service are readily distinguishable from general system facilities, cost thereof should be assigned to New England zone. P. 212.
11. In adjusting Mcf-mile method with respect to New England zone, Commission employs Docket No. G–5259 revenue levels to apportion fifty-percent of demand and commodity costs to provide reasonable means of insuring long deferred transition to Mcf-mile cost allocation in a gradual and orderly manner without unduly disrupting marketing patterns developed by Tennessee's customers. P. 213.
12. Commission *concludes* it both fair and reasonable to allocate to peaking and storage services costs equal to the total revenues actually realized, such costs to be deducted from system-wide costs before application of allocation method herein approved. P. 213.
13. Commission *rejects* use of average monthly billing demands for allocation of demand responsibility; finding this departure from usual practice of using actual peak period is not adequately supported by the evidence. P. 214.
14. Commission *determines* principles and methods of allocation for Tennessee's system under Section 4(e) of the Natural Gas Act. P. 215.

Harry S. Littman, Jack Werner, and *William C. Braden, Jr.* for Tennessee Gas Transmission Company.

W. O. Crain, G. D. Fiser, C. H. Lewis, Vernon Woods, and *E. J. Frieberg* for United Gas Pipe Line Company.

James O'Malley, Jr., and *Halcyon G. Skinner* for Consolidated Edison Company of New York, Inc.

Carl E. Hartley and *William W. Bedwell* for East Tennessee Natural Gas Company.

James O. Watts, Jr. and *S. Bolling Hobbs* for Commonwealth Natural Gas Corporation.

James R. Lacey, William R. Duff, J. Harry Mulhern, John F. McDonald, Edward S. Kirby, and *Frederick M. Broadfoot* for Public Service Electric and Gas Company.

John T. Brown for Equitable Gas Company.

John H. Hollands for Iroquois Gas Company and Pennsylvania Gas Company.

David K. Kadane and *Edward M. Barrett* for Long Island Lighting Company.

Charles E. McGee, Francis H. Caskin, and *R. H. Christiansen* for United Natural Gas Company.

Albert J. Feigen for Alabama-Tennessee Natural Gas Company.

Ray O. Martin for East Ohio Gas Company.

Denton Borger for Hope Natural Gas Company.

G. Kirby Harrington for New York State Natural Gas Corporation.

James B. Sayers for Peoples Natural Gas Company.

Spencer W. Reeder, C. W. Cooper, George C. Williams, and *Norman A. Flaningam* for Consolidated Natural Gas System Companies.

Julian De Bruyn Kops and *Roy D. Boucher* for Dayton Power and Light Company.

Christopher T. Boland and *Thomas F. Ryan, Jr.* for Texas Gas Transmission Corporation.

John T. Miller, Jr. and *Thomas F. Ryan, Jr.* for Lake Shore Pipe Line Company.

Franklin B. Gilmore for North Penn Gas Company.

Tilford A. Jones for United Fuel Gas Company.

W. F. Laird and *W. A. Batten* for Ohio Fuel Gas Company.

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William Anderson and *W. A. Batten* for Manufacturers Light and Heat Company.

W. D. Spears for Chattanooga Gas Company.

Gavin H. Cochran, and *Samuel R. Wells* for Louisville Gas and Electric Company.

Warren W. Kinnerly for City of Knoxville, Tennessee.

William Baxter and *Richard F. Ober* for Baltimore Gas and Electric Company.

Cameron F. MacRae, *Justin R. Wolf*, *Eugene Threadgill*, and *Louise Powell* for Rockland Power and Light Company.

Gordon L. Mazor for Lake Shore Gas Company.

Harold W. Gee and *W. D. Spears* for Volunteer Natural Gas Company.

Earl L. Dey and *Leonard S. Zartman* for Rochester Gas and Electric Corporation.

John L. Wallace for City of Lewisburg, Tennessee.

S. S. McNeer for Ben Williamson, Jr., Trustee In Bankruptcy, Inland Gas Corporation.

Walter E. Beckjord and *Richard H. Rhein* for Cincinnati Gas and Electric Company and Union Light, Heat and Power Company.

Edwin F. Russell, *Robert B. Lisle*, and *Harry G. Hill* for Brooklyn Union Gas Company.

C. Oscar Berry and *Karl Michelet* for Washington Gas Light Company.

William A. McClain, *Robert J. White*, and *Henry M. Bruestle* for City of Cincinnati, Ohio.

John W. Glendening, Jr., for The Berkshire Gas Company; The Connecticut Gas Company; Gas Service, Inc.; Haverhill Gas Company; The New Britain Gas Light Company; and City of Westfield Gas and Electric Light Department.

John W. Glendening, Jr. and Francis R. Foley for Blackstone Valley Gas and Electric Company.

John W. Glendening, Jr. and *N. K. Parsells* for the Bridgeport Gas Company.

John W. Glendening, Jr. and *Charles H. Tool, Jr.*, for Concord Natural Gas Corporation and Manchester Gas Company.

John W. Glendening, Jr. and *H. Bissell Carey, Jr.*, for Connecticut Power Company.

John W. Glendening, Jr. and *William R. Cook* for Fitchburg Gas and Electric Light Company and Springfield Gas Light Company.

John W. Glendening, Jr., and *Frank J. Coyle* for The Greenwich Gas Company.

John W. Glendening, Jr., and *John F. Moriarity* for City of Holyoke, Massachusetts Gas and Electric Department.

John W. Glendening, Jr. and *Harold E. Drew* for Housatonic Public Service Company.

John W. Glendening, Jr. and *Edmund L. Twomey* for Lowell Gas Company.

John W. Glendening, Jr. and *Henry R. Mayo, Jr.*, for Lynn Gas and Electric Company.

John W. Glendening, Jr. and *D. G. Allen* for Central Massachusetts Gas Company; Lawrence Gas Company; Mystic Valley Gas Company; Northampton Gas Light Company; North Shore Gas Company; and Wachusett Gas Company.

John W. Glendening, Jr. and *William A. Hill* for Worcester Gas Light Company.

John T. Miller, Jr. and *G. E. Creber* for Niagara Gas Transmission, Ltd.

William E. Guilian for United States Atomic Energy Commission.

Christopher T. Boland and *Thomas F. Ryan, Jr.*, for Pike Natural Gas Company.

George Foster, Jr. and *Harry L. Briston* for New York State Electric and Gas Corporation.

James L. Bomar, Jr., for Tennessee Gas Company; City of Athens, Tennessee; City of Clarksville, Tennessee; Cleveland Natural Gas Company; City of Cookesville, Tennessee, Elk River Public Utility District, Tullahoma, Tennessee; City of Fayetteville, Tennessee; City of Gallatin, Tennessee, and City of Springfield, Tennessee.

John V. Matthews for City of Fayetteville, Tennessee.

Richard H. Lee and *David M. Brackman* for Department of Public Utilities of the Commonwealth of Massachusetts.

James O. Watts, Jr., S. Bolling Hobbs, and *Michael E. Shea* for Lynchburg Gas Company.

Kent H. Brown, Lawrence M. De Vore, Charles J. Cox, and *Barbara M. Suchow* for New York Public Service Commission.

George Shuff and *Harold Seligman* for Tennessee Public Service Commission.

Benedict W. Larrington and *Grover C. Richland, Jr.*, for the State of New Jersey and the Board of Public Utility Commissioners of the State of New Jersey.

John A. Lodge for Consolidated Edison Company of N.Y., Inc.

Tilford A. Jones and *Edward B. Calland* for Columbia Interveners.

Harry Cramer for Manufacturers Light and Heat Company.

William R. Joyce, Jr., for Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc.

James A. Biddison, Jr., for Baltimore Gas & Electric Company.

Ralph S. Locher and *James L. Harkins, Jr.*, for City of Cleveland, Ohio.

Jacob Goldberg for North Pennsylvania Gas Company, Port Alleghany, Pennsylvania.

John S. Schmid for Berkshire Gas Company, et al.

S. David Freeman for Tennessee Valley Authority.

David Stahl, Charles S. Rhyne and *Herzel H. E. Plaine* for City of Pittsburgh.

Abraham R. Spalter for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SWIDLER, *Chairman:*

This proceeding originated on January 14, 1957, when Tennessee Gas Transmission Company filed tariff rate changes reflecting an aggregate increase of about $24,000,000 in annual revenues. These rates went into effect, subject to refund, on July 14, 1957, and were superseded on May 15, 1959, when further increased rates filed by Tennessee in Docket No. G–17166 became effective. On April 30, 1959, the Commission ordered that the cost of service issues in this proceeding be postponed and that a separate and prior hearing be held on the issues relating to the principles and methods for allocation of costs among the zones and among the classes of service on Tennessee's system. On February 13, 1961, the presiding examiner issued his initial decision on the principles of allocation among zones and certain related issues. Exceptions were filed by the interveners and the staff. Oral argument was heard by the Commission on May 9, 1961, and on September 22, 1961.

The selection of appropriate methods of cost allocation and the explication of the underlying principles by which such methods can be evaluated are among the most important responsibilities of this Commission. Although eighteen years have elapsed since Tennessee was granted its original certificate, this is the first case in which the allocation issues arising out of the complex operation of the Tennessee system have been fully heard and presented to the Commission on a complete record. Since the allocation method is a fundamental part of every pending and future Tennessee rate case, it is imperative that

these basic issues be determined herein. We have been greatly assisted in this difficult task by the comprehensive and penetrating analysis provided by the presiding examiner in his initial decision in this phase of the proceeding. In general, we concur in his well-reasoned presentation of the allocation problems and other issues, and, except to the extent modified by this opinion, we adopt his conclusions.

We note at the outset our agreement with the examiner's rejection of the Consolidated Companies[1] contentions with regard to burden of proof. Since we find that the record, to which all the parties contributed, sufficiently supports our determination of a reasonable method of allocation, it is now immaterial whether the applicant, Tennessee, has sustained its alleged burden of proof on the issue as originally presented. This view enables us to adopt the examiner's summary of the present status and primary purpose of this proceeding:

> In the G–11980 rate filing Tennessee squarely raised the zoning issue. Accordingly, on July 1, 1957, Tennessee filed a motion to dismiss the zone allocation issue in Docket G–5259, contending that the zoning issue should be litigated and resolved once and for all in the instant G–11980 proceeding. All parties agreed to this motion, for the reasons indicated, and the motion was granted by Commission order of September 5, 1957.
>
> It is apparent from the above recital that up to this date the Commission has never previously considered or decided, on the merits, the proper allocation of Tennessee's costs among its zones or the proper zone rate differentials. It is further apparent that the Docket No. G–5259 zone differentials, with some slight modifications, represented basically the zone differentials which were worked out and agreed on by the parties, and accepted by the Commission in 1952 as part of the rate settlement in Docket G–1741; that these zone differentials were thereafter incorporated, with the slight modifications referred to above, in every succeeding Tennessee rate case, because of the desire of the parties to postpone the litigation and final resolution on the merits of this complex and troublesome problem.
>
> In the instant proceeding, however, pursuant to the Commission's order of severance of April 30, 1959, the zoning issue has been fully tried and comprehensively briefed, on the merits. Although the instant Docket No. G–11980, as a result of Tennessee's later rate increase filing in Docket No. G–19983, has now become purely a refund case with respect to the dollar cost-of-service issues, the instant proceeding has nevertheless become the vehicle for final resolution of the zoning question. Whatever allocation method may be here adopted for the allocation of Tennessee's total system costs between its existing zones will be applicable to the Tennessee system for the future—unless and until it may be demonstrated at some later date that a change is required.

Methods of Allocation

Two fundamentally different methods of allocation have been proposed for the Tennessee system, one based on rolled-in system-wide average costs and mileage, the other segregating and assigning to each of the six zones the costs associated with the particular facilities located within the zone. The controversy concerns the allocation of transmission costs, since all parties agree that gas supply and gathering costs should be rolled-in and allocated to volumes on a uniform average basis.

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[1] Hope Natural Gas Company, The East Ohio Gas Company, The Peoples Natural Gas Company, New York State Natural Gas Corporation, and Lake Shore Pipeline Company.

Tennessee, the New England interveners,[2] and the staff employ the *Mcf-mile method:* the volumes delivered at each point within a particular zone are multiplied by the number of miles from source of supply to such point to derive a total number of Mcf-miles for each zone; rolled-in system-wide transmission costs are allocated to each zone according to the ratio of the individual zone's Mcf-miles to the Mcf-miles of the system as a whole.

The Columbia[3] and Consolidated companies are the principal advocates of the *zone-by-zone method:* the transmission costs associated with the facilities physically located within each zone are assigned to the zone as if it were a separate operating entity which purchases gas from the next upstream zone and sells it to its own customers and to the next downstream zone; the transmission costs assigned to a particular zone (plus its cost of gas "purchased" from the next upstream zone) are allocated to all volumes sold in that zone or delivered to the next downstream zone on a uniform average basis.

Both of these methods classify costs between the demand and commodity functions substantially in accordance with the established *Seaboard* formula. (Opinion No. 225, 11 FPC 43). The Columbia companies did not pursue their opposition to this formula in their exceptions.

The fundamental principles and problems involved in the choice between these two methods are well stated in the following quotation from the examiner's decision:

> At the outset it is important to recognize that there are "pluses" and "minuses" with respect to each of the varying and conflicting zone allocation methods proposed in this case, and that none of these methods are free from problems or difficulties. As realistically noted by Tennessee:
>
> "An argument can be made for a uniform rate for all customers * * * An argument can also be made for different rates for each customer based on the 'cost' incurred in serving each customer. An argument can be made, as Columbia and Consolidated do, for segregating 'costs' within a geographical area. An argument can be made for rates based on mileage. An argument can be made for rates based on historical differentials. An argument can be made for rates based on a combination of mileage and historical factors. Something can be said in favor of each of such methods of allocation or rate-making. The difficulty lies in selecting the method. No one method can lay claim to being the 'right' method * * * the selection of the method of allocation to be used is bottomed on fairness and the exercise of judgment."
>
> The Supreme Court recognized this inherent characteristic of cost allocation problems in *Colorado Interstate Gas Co.* v. *F.P.C.*, 324 U.S. 581 (1945), as follows:
>
> "Allocation of costs is not a matter for the slide rule. It involves judgment on a myriad of facts. It has no claim to an exact science. Hamilton, Cost as a Standard for Price, 4 Law and Cont. Prob. 321. But neither does the separation of properties which are not in fact separable because they function as an integrated whole. (324 U.S. at 589) * * *
>
> "These circumstances illustrate that considerations of fairness, not mere mathematics, govern the allocation of costs." (324 U.S. at 591)
>
> Similarly, the United States Court of Appeals for the Tenth Circuit in a subsequent case involving the same company, *Colorado Interstate Gas. Co.* v. *F.P.C.*, 209 F. 2d 717, at 726 (1953), stated:

[2] Comprising some 25 New England distribution companies and municipalities, which participated jointly in the proceeding.

[3] The Manufacturers Light and Heat Company, The Ohio Fuel Gas Company, and United Fuel Gas Company.

"* * * True, it did say that neither method was entirely satisfactory, but the same could be said with respect to any method which might be proposed. Mathematical exactness in the apportionment of cost is an impossibility. Because a method may have some infirmities does not of itself condemn it as a proper method. It is the duty of the Commission to select that method which in its considered judgment more nearly reaches a just and sound result."

In approaching the problem of determining here which of the proposed allocation methods should be adopted for the Tennessee system, each of the alternative allocation methods has been measured against the following basic requirements:

(1) The method selected should assign a fair share of the total system cost of service to each of the zones.

(2) The method selected should be a practical one. It should not be so complex as to require long, tedious studies involving speculations and assumptions, but rather should be a method which can be expeditiously applied to facts quickly ascertainable.

(3) The results reached, through applying such method, should make sense.

As earlier noted, the threshold question in this proceeding is whether system-wide average costs, on a mileage basis, are to be employed, or whether segregated zone costs should be employed. Despite the numerous arguments and counterarguments advanced here, and the plethora of problems requiring detailed analysis, the ultimate determination to be made comes down to a choice between two basic philosophies or approaches:

(1) The philosophy that the Tennessee system is a single, integrated pipeline system, operated as a single entity, with each part of the system contributing to every other part; that accordingly, although customers closer to the source of supply should pay less than customers located farther away from the source, all customers, as customers of a single, integrated pipeline system, should pay on the basis of average system-wide costs for each mile of transmission.

(2) The conflicting philosophy that costs should be segregated by zones so that the customers in each zone would be treated as if they were customers of separate operating companies. This approach emphasizes the fact that the unit cost of transmission varies in different areas, and insists that an appropriate allocation method must give specific zone by zone effect to such differences in cost.

The examiner's decision also contains a detailed analysis of the two basic allocation methods to which he refers and of the history and characteristics of the Tennessee system. We adopt this analysis and concur in the examiner's findings that Tennessee operates a fully integrated transmission system, that it provides essentially the same type of pipeline service in all of its zones, and that the zone boundaries do not correspond to any actual divisions in system operations or service. With respect to such a system, it is obviously impossible to identify the portion of its main-line facilties which was installed or is used specifically for the benefit of any individual customer. The Tennessee system is a particularly good example of such a system. It has expanded to ten times its original capacity and is now operated in conjunction with storage facilities which, although located in Pennsylvania, affect the costs of pipeline operation in all zones and benefit every customer in an indeterminate amount. In order to reflect the unity of operation and interdependence of service on an integrated pipeline of this type, it has long been Commission policy to use a system-wide average of mainline transmission

costs as the foundation for any allocation of costs to zones or classes of customers.[4] This policy has the advantage of administrative simplicity, but, more important, the sharing of system costs on a system-wide basis is a fairer and more rational concept of allocation than any attempt to guess what it might cost to serve each individual customer separately. Even the zone-by-zone method gives at least partial recognition to this policy by requiring that all costs assigned to a particular zone be averaged among all volumes of gas transported in that zone irrespective of point delivery. For the reasons outlined above, it is our opinion that as between two allocation procedures both economically defensible, that one should be preferred which minimizes the differentials in zone rates.

This is not to say that differences in costs over a system as large as Tennessee's should be completely ignored by adopting the "postage stamp" concept of rate-making. Such use of the average cost method without zone differentials would, in the circumstances of the present case, result in undue discrimination. In other cases of this type, the determination of the extent to which modification of the average cost method is required has been based upon a consideration of the three most significant determinants of the costs of pipeline operations, namely, load factor, load density, and distance of transmission. However, there are certain difficulties inherent in translating differences in operating characteristics into reasonable cost differentials. The cost consequences of each of these factors, considered separately or in combination with the others, are not precisely measurable. Moreover, the process of comparing, evaluating, and giving effect to variations in these factors is itself based on a necessarily arbitrary division of a unified system into areas or zones. Consequently, as was stated earlier in more general terms, the relative weight to be given in each case to one or more of these factors is a matter of judgment on which reasonable and informed men might differ.

Of the three factors to be considered, distance of transmission has the most constant and predictable relation to cost. Thus, where the zones of a pipeline system have no extreme variations in load factor or load density, the distance factor can, by the Mcf-mile method described above, be applied directly to system-wide costs to provide an allocation which gives reasonable effect to the increase in the cost of transmission in each successive zone without disregarding the fact that the facilities in each zone are parts of an integrated system. In the *Northern* case,[5] the substantial differences in the distances of transmission to Northern's customers were considered sufficient to require some modification of the previous allocation of costs on a system-wide average basis. Zones were established, and system-wide transmission costs were allocated to each zone by the Mcf-mile method.[6] Although there were also substantial variations in load factor and in load distribution on the Northern system, it was found that the one tended to offset the other, at least to the extent that the net effects of these factors were not so great as to make the Mcf-mile unreasonable or unfair as a system-wide cost index. The Commission summarized its findings as follows:

> As previously stated, it is a simple economic fact that the delivery cost of natural gas increases in close proportion to the length of the transmission line of any given size. Therefore, unless other circumstances are present which outweigh the importance of the length of transmission required to

[4] See e.g., *Canadian River Gas Company*, 3 FPC 32 (1942), aff'd 142 F. 2d 943, aff'd 324 U.S. 581; *Trunkline Gas Company*, 21 FPC 704 (1959), aff'd 281 F. 2d 42; *El Paso Natural Gas Company*, 22 FPC 260 (1959), rev'd on other grounds 281 F. 2d 567.

[5] *Northern Natural Gas Company*, 14 FPC 11 (1955), aff'd 236 F. 2d 372.

[6] See also *Kansas-Nebraska Natural Gas Company*, 25 FPC 448 (1961).

> effect delivery, the distance factor is the prime determinant of the cost of rendering service. Since in our view of this record there are no such circumstances present to counterbalance the distance factor, we conclude that the distance of transmission required to effect deliveries at the various points of sale by Northern reflects with reasonable accuracy the relative cost of providing service to its customers. (14 FPC at pg. 24)

The Columbia and Consolidated companies urge the Commission to reject the Mcf-mile method in this and all future cases since it does not attempt to determine the "actual" costs of rendering service in each zone. They contend that the zone-by-zone method does reach this result by considering separately the costs arising in each zone. These parties recommend that the long-established system-wide average cost principle be abandoned in favor of the segregation of system facilities into artificial zone units as the primary basis for the allocation of system costs. It appears to us that the zone-by-zone method would give Tennessee's zone boundaries, which were established at state lines largely as a matter of convenience, a significance entirely unwarranted by actual system operations. For the reasons mentioned earlier there is no objective formula for determining the "actual" cost of serving one or more customers from an integrated pipeline system. The zone-by-zone method does not achieve this illusory goal. Instead, it merely assumes that the "actual" unit cost of serving any of the customers located, for example, in Tennessee's Southern zone is equal to the average unit cost of the facilities that happen to be located in that zone. This assumption ignores the fact that the low unit costs of the facilities in the Southern zone are largely attributable to the very large volumes transported through that zone for sale further downstream and to the very high load factor operation of these facilities made possible by the use of storage in conjunction with the main-line facilities downstream. Thus it appears that the zone-by-zone method, by insulating the upstream zones from all costs of downstream main-line facilities, would give the customers in those zones an undue share of the economies realized from the operation of the system as a whole. In a few instances, to meet particular problems and conditions, it has been necessary and appropriate to assign directly the costs of the facilities used for a single customer,[7] but the segregation, contemplated by the zone-by-zone method, of all main-line facilties has never been approved as a basis for the allocation of the transmission costs of an integrated system.[8] Such a method was rejected in the *Northern* case, *supra*, and, in our judgment, is inappropriate for the Tennessee system.

A review of the briefs and exceptions filed in the present proceeding indicates that the principal objection to the Mcf-mile method is, not that it is unreasonable as applied to the first five Tennessee zones, but that it fails adequately to reflect the special characteristics of the last, New England, zone. The evidence of the operating characteristics of the Tennessee system indicates that the differences in load factor are somewhat greater, while the variations in load distribution are substantially less, than those on the Northern system, for which the Mcf-mile method was found appropriate. In the present case, the record shows that very substantial volumes of gas are delivered in each of the Tennessee zones and no one zone has a dominant share of system sales. In our judgment, the variations in load factor or load density in the Tennessee zones do not have such an unbalancing effect on system operations as to make

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[7] See *Trunkline Gas Company, supra*, note 4.

[8] In the *United Gas* case, cited by the Columbia companies, it was concluded that United's transmission costs could not realistically be allocated on a rolled-in basis for the reason that United's intricate and varied network is not operated as an integrated pipeline system. *United Gas Pipe Line Company*, Docket No. G-9547, 25 FPC 26 (1961).

the Mcf-mile an irrational measure of cost for the system as a whole. On the other hand, it is apparent that the New England zone has somewhat higher cost characteristics than the rest of the system. These considerations do not, in our opinion, warrant the abandonment of the Mcf-mile method for the entire Tennessee system; they narrow the issue to the question whether any special adjustment in this method is required by the characteristics of service to New England.

The New England Zone

The record in the present case contains much comment on what the examiner terms the "unfavorable characteristics" of the New England zone but nothing of a conclusive nature as to their precise effect in the context of the system-wide application of the Mcf-mile method. There is wide disagreement as to the size and importance of differences in these characteristics and no fully adequate method is proposed for translating such differences into appropriate cost differentials. The Columbia companies have suggested that the proper method of allocating costs to New England was decided in 1954 by a condition imposed in the *Northeastern* merger case[9] which required Tennessee to keep separate records of the costs of service in the New England zone. As more fully discussed in the examiner's decision herein, this condition was part of an order issued on a limited record in a certificate proceeding and it could not, in the circumstances, predetermine the method of cost allocation to be adopted in a future rate case.

The principal characteristics which, it is contended, unduly and adversely affect costs in New England are load density, load factor, excess capacity, and city-gate service. With regard to all but the last of these, the various analyses have been based on the 1956 test year data reflected in the staff's cost-of-service, which was used by the parties to illustrate and compare the dollar results of the proposed methods. In selecting a fair and reasonable method of allocation to be applied in years subsequent to 1956 and in the future, some consideration must be given to more recent volumetric data such as that filed in the record in Docket No. G–19983 which relates to Tennessee's deliveries during the twelve months ended July 31, 1959.[10]

With regard to the relative size of the New England load and the type of adjustment by which this factor might properly be reflected, the evidence and the briefs are indefinite. In 1956, 36 million Mcf were delivered in the New England zone, while 59 Million Mcf were delivered in the Central zone. However, by 1959 the New England zone load had increased to 52 million Mcf, while the Central zone load had diminished to 56 million Mcf. It is also relevant to note that according to Tennessee's estimates, recently filed in Docket No. CP60–94, in 1963 the New England zone load will exceed 70 million Mcf as compared with estimated deliveries of 54 million Mcf in the Central zone. In view of this indicated growth of the New England load, an adjustment for load density in that zone does not appear to be necessary.

As to the New England zone load factor, it appears that the staff figure of 48.6 percent is unreasonably low, for purposes of comparison, owing to substantial increases in the annual volumes delivered after the January 1957,

[9] Order issued July 16, 1954, *In the Matters of Tennessee Gas Transmission Company and Northeastern Gas Transmission Company*, Docket Nos. G–2352 and G–2353, authorizing the merger between Tennessee and Northeastern. 13 FPC 631.

[10] Although such data is not a part of the evidence in the present case, it may properly be considered, with some allowance for necessary adjustments, since it is a matter of public record the mathematical accuracy of which is rarely disputed.

three-day peak employed by the staff. The New England interveners contend that if annual volumes were properly related to peak volumes, and if the volumes delivered under the temporary PS–G rate schedule were eliminated from the calculation, the zone load factor would exceed 65 percent in 1956–57, and would be approximately 72 percent in 1958–59, as compared with 73.2 percent for the Southern zone in the later period. The importance of such comparisons has been greatly exaggerated. The lower-than-average New England load factor applies only to the pipeline facilities north of the storage fields. The use of storage enables Tennessee to operate the facilities required for service to New England from storage southwest to source of supply at close to 100 percent load factor. We are of the opinion that the foregoing considerations sufficiently demonstrate that an adjustment based on the New England load factor is not appropriate.

The Columbia companies have given considerable emphasis to the question of excess capacity in New England. As the examiner points out, this is an extremely complex matter, but one on which none of the parties presented a detailed study. Columbia's witness gave 354,000 Mcf as his "impression" of New England's peak day capacity in 1956, but this was reduced to 339,445 Mcf in Columbia's exceptions. The evidence adduced in support of the amended certificate application [11] for the facilities actually constructed in New England in 1951 contains delivery estimates of about 250,000 Mcf per day for normal service, plus 50,000 Mcf for emergency weather conditions in New England, and an additional 30,000 Mcf capacity allowance for emergency interchange of gas between the Northeastern and Algonquin systems. The actual peak deliveries in January 1957 were 205,981 Mcf, which increased to 260,384 Mcf in the winter of 1958–59. The estimate for 1963 is 323,000 Mcf. These figures indicate that the capacity constructed in New England, although delayed in its full utilization, has proved necessary for service in that zone. There has been no showing that the construction of this capacity would have been less expensive at the increased cost levels now prevailing. The record as it stands will not support a finding that such excess capacity as may have existed in the New England zone since 1957 is unreasonable or requires a specific adjustment to the allocation method adopted herein.

From what we have said about relative size of load, load factor, and excess capacity, it is not necessarily to be inferred that if, on a relative basis, the New England load were small, the load factor low, or excess capacity high, the New England consumers should bear the resulting economic burden, for there might be circumstances which would warrant a different result. However, we do not reach this point in our view of the record. In our judgment, the only characteristic of the New England zone which requires a departure from the Mcf-mile method, as a matter of allocation principle applied to the facts of record, is the city-gate service. As pointed out by the Columbia companies, a basic difference between the New England zone and the rest of the Tennessee system lies in the fact that, in the New England zone only, Tennessee renders a city-gate service by means of numerous small-diameter laterals extending from the main-line to the city-gates of the communities served. The diameter of much of the pipe in the New England zone ranges from twelve inches down to three inches, whereas the smallest diameter of pipe anywhere else on the system is sixteen inches. The facilities required for this special type of service are readily distinguishable from general system facilities, and the costs thereof should be assigned to the New England zone. In this connection the following

[11] See order issued March 21, 1951, in *Northeastern Gas Transmission Co.*, Docket No. G–1267, 10 FPC 135.

remarks from a recent decision of the U.S. Court of Appeals for the District of Columbia Circuit are pertinent:

> At some point in every gas distribution facility the general system ends and connective links to the local distributors' own equipment begins. At this point the facility becomes so identified with its function as a part of the local distributor's gas plant that it may be unfair to charge its cost to all of the customers of the utility. *Battle Creek Gas Company* v. *Federal Power Commission*, 281 F. 2d 42, 46 (CADC 1960).

As a basis for calculating the actual dollars of cost to be so allocated, a determination must be made of the portions of the New England system which should be classified as main-line facilities. The map attached to this opinion, as Appendix A, indicates the points beyond which, considering the location and size of the particular lines, and the volumes delivered thereby, the facilities may appropriately be identified as lateral facilities, in the context of the Tennessee system.

The Historical Revenue Pattern

In order to adjust the Mcf-mile method to take account of the "unfavorable characteristics" of the New England zone, the examiner adopted Tennessee's proposal to allocate system costs fifty percent by the Mcf-mile method and fifty percent on the basis of the historical revenue pattern reflected in the Docket No. G–5259 rates. As an adjustment for this purpose, such use of the historical revenue pattern is too broad since it is applied to all zones and is not directly related to the particular operating characteristics of the New England zone. Nevertheless, we are of the opinion that the Docket No. G–5259 revenue levels should be employed to apportion fifty percent of the demand and commodity transmission costs herein for the reason that it will provide a reasonable and practical means of insuring that the long-deferred transition to an Mcf-mile cost allocation will be accomplished in a gradual and orderly manner without unduly disrupting the marketing patterns which have been developed by Tennessee's customers. The G–5259 revenue levels should be used in this same manner in the pending rate proceedings in Docket Nos. G–17166 and G–19983, since this transition will now actually take place during the period involved in the latter case.

Other Issues

Storage and Peaking Services

The examiner analyzes in some detail the special characteristics and basic similarities of the storage service (SS–5) rendered in the New York zone and the peaking service (PS–G) rendered on a temporary basis in the New England zone. He points out the weaknesses of various allocations proposed and adopts (for SS–5) a method based on a segregation of the costs of the facilities used to render the service. While this method may not be erroneous in principle, its application in practice presents the greatest difficulties in attempting to identify the specific portions of Tennessee's storage and pipeline facilities actually used for these services. The complexity of this problem has been increased by the addition in 1957 of the Colden storage facilities to Tennessee's northern line in the New York zone, and no adequate solution is suggested by the evidence. Thus, in the present record, an allocation to these services of costs less than the revenues realized therefrom has not been justified. On the other hand, it appears from the Commission's decisions in Docket Nos. G–10804 [12] and G–11107 [13] that

[12] 19 FPC 568.
[13] 21 FPC 70.

no additional facilities were authorized for these services. Tennessee's witness testified, without contradiction, that the incremental cost of the more expensive service (PS–G) was less than twenty cents per Mcf. It is evident from this that at the rates in effect during this period (90 cents for PS–G and approximately 67 cents for SS–5) these sales would recover a very substantial amount of system costs which would otherwise be borne by regular service. All or a portion of this benefit to the system as a whole might have been lost at higher rates. From these considerations we conclude that it is both fair and reasonable to allocate to these services costs equal to the total revenues actually realized, such costs to be deducted from system-wide costs before application of the allocation methods approved herein.

Demand and Commodity Volumes

As the basis for calculating the Mcf-miles for each zone the examiner and the staff use the 1956 annual volumes related to average deliveries during a three-day peak period occurring in January 1957. Most of the questions raised with regard to adjustments to these volumes are not material since the methods herein approved will be applied, in the first instance, to the locked-in period from July 14, 1957, to May 15, 1959, on the basis of the volumes actually deliverd during the year ending June 30, 1958, and during the year beginning July 1, 1958. Nevertheless, we should note our concurrence in the examiner's conclusion with regard to the contention of the New England interveners that the three-day system peak may give a distorted picture of the customer's actual use of peak capacity in that it may not fully or properly reflect differences in weather conditions in widely separated areas of service. These parties recommend the use of average monthly billing demands for the allocation of demand responsibility. However, no study was presented which satisfactorily demonstrates that a hypothetical peak day delivery equal to the sum of the customers' average billing demands is, in fact, more representative of the design and maximum use of integrated system facilities than the actual system peak. This departure from the usual practice of using an actual peak period for the determination of demand charges is not adequately supported by the evidence herein and should not be adopted.

Allocation of Demand Costs to Seller's Option Service

As more fully described in the examiner's decision, Seller's Option (SO) is an off-peak service rendered by Tennessee in the Eastern, Northern, and New York zones. Under the SO rate schedules, Tennessee has an obligation to deliver, at times of its own choosing, a fixed annual volume of gas, and the buyer must pay for any volumes so tendered, whether taken or not. We agree with the examiner that, since no new facilities have ever been constructed for this service, Tennessee's proposed increase in the demand costs previously allocated to this service is not justified. The historical method of charging SO service with a demand responsibility equal to fifty percent of the demand responsibility of regular (contract demand) service at 100 percent load factor is reasonably related to the operating characteristics of this service and its proportionate use of system facilities. This method provides an appropriate basis for calculating the demand-miles for SO service to be included in the total for the zone in which such service is rendered. The formula also insures that each zone in which SO gas is delivered will have allocated to it the fair share of system demand costs which this service should bear, and it will avoid distorting the amount of cost allocated to other classes of service. However, any SO volumes which, under abnormal circumstances, happen to be delivered during the three-day peak period—at Tennessee's option, it should be emphasized—will be eliminated from the calculation of system demands.

In order to give some general indication of the effects of our determinations, the tables in Appendix B to this opinion set forth an estimate of the zone cost results of the methods and principles of allocation approved herein, as applied to the 1956 test year data. These figures reflect a rough approximation of the effect of the special adjustment adopted for the New England zone, and they are provided for purposes of illustration only.

The Commission orders:

(A) The following findings and conclusions from the presiding examiner's decision herein are adopted and made part of this order:

(1) The Tennessee system is divided into six rate zones, namely, Southern (Zone 1), Central (Zone 2), Eastern (Zone 3), Northern (Zone 4), New York (Zone 5) and New England (Zone 6). The Commission has not previously determined a method by which Tennessee's cost of service should be allocated among its rate zones and classes of service.

(2) Tennessee operates an integrated pipeline system, in which every portion of the system contributes in one way or another to the effectiveness of the entire system, whether directly or by displacement.

(3) Both Columbia and Consolidated advocate a zone-gate (or zone-by-zone) allocation approach whereby each rate zone is treated as if it were a separate operating entity, and involving the segregation of physical property on the basis of zone boundaries. The zone-gate approach is inconsistent with the basic principles upon which Tennessee's integrated system was designed and is operated. In addition, it accentuates the impact upon cost allocation resulting merely from the historical location of the geographical zone boundaries on the Tennessee system. It is also unduly complex.

(5) The Mcf-mile approach, which uses system-wide average costs, and allocates such costs on the basis of mileage, constitutes, in general, a fair and reasonable method for the allocation of costs between zones on the Tennessee system.

(9) The Tennessee method for allocation of costs to Transportation Service, utilizing the mileage from the actual points of receipt of transportation gas to the points of delivery, is reasonable.

(10) The Iroquois complaint that the use of the Pennsylvania-New York state boundary as a dividing line between the Northern and New York Zones is unfair and discriminatory has not been supported in this record.

(B) In allocating demand costs under the Mcf-mile method herein, demand volumes will be measured on the basis of the three-day sustained peak periods (adjusted for any obvious abnormalities) in the two winter seasons of the refund period herein, and not on the basis of average billing demands.

(C) The demand costs for SO service will be based on the number of demand units equal to fifty percent of the CD demand responsibility at 100 percent load factor.

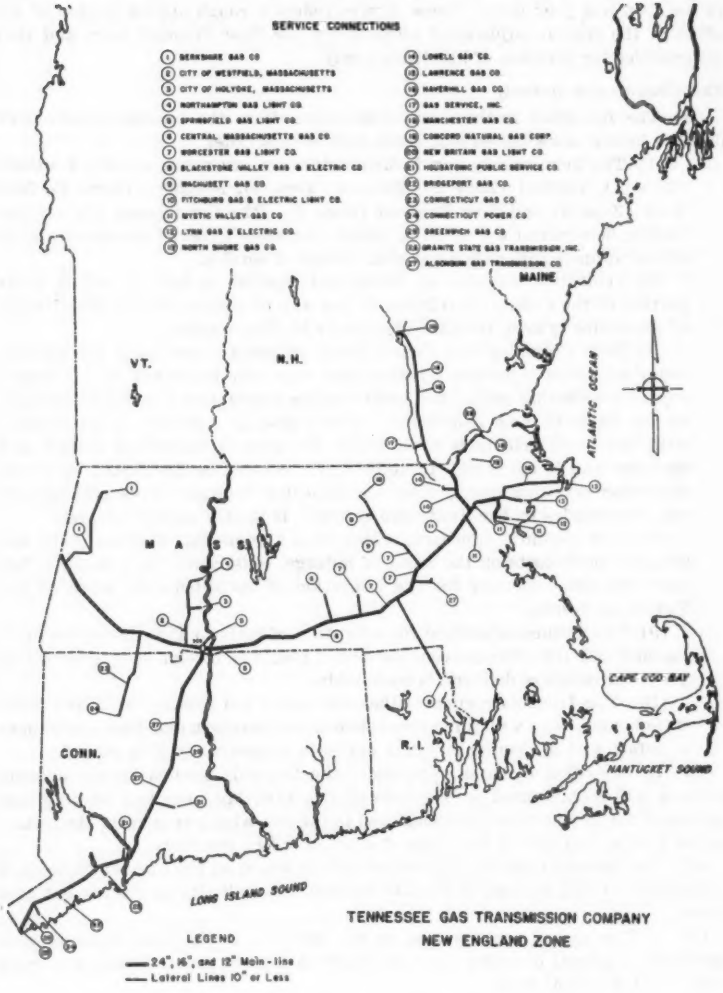
(D) 1. The annual costs related to the facilities in the New England zone classified as lateral facilities shall be deducted from system transmission costs and allocated to that zone;

2. The revenues received from SS–5 and PS–G service shall be deducted from system costs and allocated to those services; and

3. The remaining transmission costs shall be allocated fifty percent by the methods prescribed in paragraphs A(5), A(9), B, and C, and fifty percent on the basis of the Docket No. G–5259 revenue levels.

APPENDIX A

DOCKET NO. G-11980



TENNESSEE GAS TRANSMISSION COMPANY
NEW ENGLAND ZONE

APPENDIX B

Allocation of transmission system costs to zone sales and transportation services, 12 months ended Dec. 31, 1956

	Allocation factors for transmission cost				Allocation of production cost	Allocation of PSG and SS-5 cost	Allocation of cost on New England laterals	Allocation of 50 percent of balance of transportation costs on G-5259 revenue level		Allocation of 50 percent of balance of transportation costs on Mcf-mile basis		Total cost of service
	G-5259 revenue level		Mcf-miles									
	Demand	Delivery	Demand Mcf-miles	Commodity 100 Mcf-miles				Demand	Commodity	Demand	Commodity	
SALES												
Southern Zone	$6,510,958	$4,551,105	237,021	648,584,399	$11,480,429			$3,251,213	$2,272,570	$3,152,448	$2,546,339	$22,702,999
Central Zone	4,676,373	4,939,622	183,994	591,508,164	7,806,570			2,335,122	2,466,574	2,447,173	2,322,258	17,377,697
Eastern Zone	15,544,822	20,339,884	681,281	2,535,976,950	28,688,652			7,762,225	10,156,614	9,061,234	9,956,232	65,624,957
Northern Zone	8,299,862	11,568,725	353,081	1,347,955,101	13,081,939	[1] $3,492		4,144,492	5,776,782	4,696,079	5,292,064	32,994,848
New York Zone	6,957,949	10,759,450	299,414	1,095,122,658	8,989,490	[2] 388,452		3,474,415	5,372,675	3,982,293	4,299,446	26,506,771
New England Zone	7,431,852	7,141,710	279,800	658,058,235	4,719,395	[1] 602,871	[3] $1,800,000	3,711,056	3,566,175	3,721,421	2,583,533	20,704,451
Total	49,421,816	59,300,496	2,034,591	6,877,205,507	74,766,475	994,815	1,800,000	24,678,523	29,611,390	27,060,648	26,999,872	185,911,723
TRANSPORTATION												
T-1	1,521,062	2,078,737	68,012	249,992,746				759,534	1,038,006	904,579	981,470	3,683,589
T-2	1,161,160	1,231,784	53,948	142,602,494				579,819	615,085	717,524	559,858	2,472,286
T-3	954,307	1,237,021	43,125	157,838,550				476,528	617,700	573,575	619,673	2,287,476
T-4	2,340,000	3,192,812	103,929	377,713,311				1,168,467	1,594,314	1,382,286	1,482,900	5,627,967
Total	5,976,529	7,740,354	269,014	928,147,101				2,984,348	3,865,105	3,577,964	3,643,901	14,071,318
Total, jurisdictional	55,398,345	67,040,850	2,303,605	7,805,352,608	74,766,475	994,815	1,800,000	27,662,871	33,476,495	30,638,612	30,643,773	199,983,041
Nonjurisdictional	288,047	38,321	944	1,883,912	453,641			143,835	19,136	12,556	7,396	636,564
Total transmission system	55,686,392	67,079,171	2,304,549	7,807,236,520	75,220,116	994,815	1,800,000	27,806,706	33,495,631	30,651,168	30,651,169	200,619,605

[1] Represents revenue from PSG sales at the 90¢ per Mcf rate.
[2] Represents revenue from SS-5 sales at the G-11980 rates.
[3] Annual cost related to lateral facilities in New England is estimated at $1,800,000.

Derivation of allocation factors

	Actual		Less SO peak deliveries		Plus imputed demand [1] factor for SO deliveries		Less adjustment for miles on New England laterals demand MMcf-miles	As adjusted		Actual—Commodity 100 Mcf-miles	Less adjustment for miles on New England laterals—Commodity 100 Mcf-miles	As adjusted—Commodity 100 Mcf-miles
	Average of 3-day peak deliveries	Demand MMcf-miles	Average of 3-day peak deliveries	Demand MMcf-miles	Peak	Demand MMcf-miles		Average of 3-day peak deliveries	Demand MMcf-miles			
SALES												
Southern	319,258	237,021						319,258	237,021	648,584,399		648,584,399
Central	184,282	183,994						184,282	183,994	591,508,164		591,508,164
Eastern	602,777	700,370	31,692	36,644	[2] 15,257	[3] 17,555		586,342	681,281	2,535,976,950		2,535,976,950
Northern	256,216	341,848			[2] 7,465	[3] 11,233		263,681	353,081	1,347,955,101		1,347,955,101
New York	175,521	281,650			[4] 10,953	[4] 17,764		186,474	299,414	1,095,122,658		1,095,122,658
New England	152,938	281,105					[5] 1,305	152,938	279,800	661,068,755	[3] 3,010,520	658,058,235
Total	1,690,992	2,025,988	31,692	36,644	33,675	46,552	1,305	1,692,975	2,034,591	6,880,216,027	3,010,520	6,877,205,507
TRANSPORTATION												
T-1	48,752	68,012						48,752	68,012	249,992,746		249,992,746
T-2	40,000	53,948						40,000	53,948	142,602,494		142,602,494
T-3	36,148	43,125						36,148	43,125	157,838,550		157,838,550
T-4	75,576	103,929						75,576	103,929	377,713,311		377,713,311
Total	200,476	269,014						200,476	269,014	928,147,101	3,010,520	928,147,101
Total jurisdictional	1,891,468	2,295,002						1,893,451	2,303,605	7,808,363,128		7,805,352,608
Nonjurisdictional	20,147	944						20,147	944	1,883,912		1,883,912
Total	1,911,615	2,295,946	31,692	36,644	33,675	46,552	1,305	1,913,598	2,304,549	7,810,247,040	3,010,520	7,807,236,520

[1] Mechanical details of the "SO" demand adjustments are shown on Sheet No. 3. Similar adjustments not made for "R" and "E" sales due to small quantities involved during 1956.

[2] (*a*) Sales of SO gas in Eastern Zone in 1956=11,168,426 Mcf.
(*b*) Item (*a*) divided by 732 days=15,257 Mcf.
(*c*) Item (*b*) multiplied by 1150.6 miles=17,555 MMcf-miles.

[3] (*a*) Sales of SO gas in Northern Zone in 1956=5,464,301 Mcf.
(*b*) Item (*a*) divided by 732 days=7,465 Mcf.
(*c*) Item (*b*) multiplied by 1504.8 miles=11,233 MMcf-miles.

[4] (*a*) Sales of SO gas in New York Zone in 1956=8,017,194 Mcf.
(*b*) Item (*b*) divided by 732 days=10,953 Mcf.
(*c*) Item (*b*) multiplied by 1621.8 miles=17,764 MMcf-miles.

[5] Computed as follows:

(*a*) *Allocation bases of PSG sales in New England*

	3-day Peak-Mcf	*Volume-Mcf*	*Dem. MMcf-miles*	*Com. 100 Mcf-miles*
Per FPC Staff Exhibits Nos. 90 and 97A	53,043	633,437	20,293	11,645,160
After removal of mileage on laterals	53,043	633,437	19,916	11,597,330
Adjustment for mileage on laterals	------	-------	377	47,830

Weighted average miles of adjustment on laterals=47,830÷633,437 or 7.55 miles.

(*b*) *Derivation of adjustment to commodity 100 Mcf-miles for volumes of PSG sales utilized herein*

PSG volumes used herein=669,857 Mcf.
Then 669,857 Mcf × 7.55 miles=50,570-100 Mcf miles.

(*c*) *Adjustment to General service sales in New England for removal of mileage on laterals in New England*

	Demand MMcf-miles	*Commodity 100 Mcf-miles*
Total adjustment to combined PSG and general service sales for removal of mileage on laterals	1,682	3,061,090
Less adjustment to PSG sales	377	50,570
Balance for general service sales	1,305	3,010,520

DECISION

UPON A PROCEEDING TO DETERMINE THE PRINCIPLES AND METHODS TO BE APPLIED IN ALLOCATING COSTS AMONG THE ZONES ON THE TENNESSEE SYSTEM, AND AMONG THE CLASSES OF SERVICE WITHIN THE ZONES

(Issued February 13, 1961)

ZWERDLING, *Presiding Examiner:* This initial decision is directed to the determination of the principles and methods to be used to allocate the cost of service of Tennessee Gas Transmission Company (Tennessee) among the six rate zones on the Tennessee system and among the various classes of service. The zone allocation issue represents one phase of the proceeding in the instant Docket No. G–11980, which represents a Section 4(e) rate increase application filed by Tennessee on January 14, 1957, proposing increased rates and charges aggregating approximately $24,077,000 annually. These increased rates went into effect on July 14, 1957, subject to an undertaking to refund any excess charges.

On April 30, 1959, after the hearing in Docket G–11980 had proceeded to the point of completion of the cross-examination of the Tennessee case-in-chief, the Commission, pursuant to a motion filed by the Consolidated Natural Gas System intervenors (Consolidated), issued an order postponing further hearings on the cost of service issues in Docket G–11980, and severing the zone allocation issue for separate and prior hearing. The order directed that hearings go forward "on the issues relating to the principles and methods proposed by the various parties for allocation of costs among the zones on Tennessee's system and among the classes of service within the zones * * *." The Commission further directed that

> * * * as the dollar basis for testing the principles and methods, the parties, without prejudice, may present cost allocation evidence based on any relevant cost of service, but shall also show the effect of restating the results of such principles and methods in terms of the proposed cost of service heretofore served by the Staff upon the parties.[1]

The order explained that:

> It is our view that separate and prior hearing on the issues relating to the principles and methods to be applied toward allocation of costs among the zones on Tennessee's system and among the classes of service within the zones will aid in the disposition of this proceeding and may be of similar aid in disposition of proceedings in Docket G–17166.[2]

Pursuant to the Commission's order of April 30, 1959, hearings were resumed on the zone allocation issue on May 12, 1959 and continued intermittently until the hearing was concluded on December 17, 1959. Testimony and exhibits on the zone allocation issue were presented by Tennessee, the Commission Staff,

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[1] Order Amending Order Severing Issues, issued May 6, 1959—amending the proviso clause contained in par. (B) of the order issued April 30, 1959.

[2] This docket represents a subsequent Section 4(e) rate increase application filed by Tennessee involving an additional proposed increase in the amount of $19,184,000, which became effective on May 15, 1959 subject to an undertaking to refund any excess charges. No hearing has been scheduled in this case. A third cumulative Section 4(e) rate increase application was filed by Tennessee on October 5, 1959 in Docket No. G–19983, proposing an additional increase in the amount of $26,590,138 annually—which became effective April 5, 1960, subject to undertaking to refund any excess charges. This latter rate proceeding is currently in an advanced stage of hearing. An interim order on rate of return, issued by the Commission on August 9, 1960 in this proceeding has rejected $11,001,825 of this third proposed rate increase, but an appeal taken by Tennessee is presently pending in the 5th Circuit.

the Consolidated Natural Gas System,[3] the Columbia Gas System, Inc. (Columbia),[4] the New England Intervenors (New England),[5] and Iroquois Gas Corporation.[6] All studies were presented on the basis of a test year ending December 31, 1956.

The record on the zone allocation issue consists of approximately 4500 pages of transcript and some 60 exhibits.[7] Final briefs were filed as of April 11, 1960, and the case is now ready for decision.

History and Characteristics of Tennessee Rate Zones

The Tennessee system is divided into six rate zones, namely Southern (Zone 1), Central (Zone 2), Eastern (Zone 3), Northern (Zone 4), New York (Zone 5), and New England (Zone 6). A map showing the boundaries of these zones is attached as Appendix A at the end of this decision.

Tennessee received its initial certificate authority in 1943 to construct and operate a transmission system having an initial capacity of 207,000 Mcf per day and extending some 1265 miles from Nueces County, Texas, to Kenova, West Virginia. (3 FPC 574) On July 22, 1947 the Commission, in connection with its rate investigation in Docket No. G–606, approved a zoning proposal which divided the Tennessee system into three zones: the Southern Zone (covering sales in Mississippi and Tennessee);[8] the Central Zone (covering sales in Kentucky); and the Eastern Zone (covering sales in West Virginia). These zone boundaries, as well as the zone rate differentials, were arrived at by agreement among Tennessee, its customers and the Staff, and the proposal was approved by the Commission on that basis. (6 FPC 114) The Northern and New York Rate Zones were created as a result of the Commission's certificate authorization in 1949, permitting Tennessee to extend its system to Buffalo, New York. (8 FPC 276, 285) In 1950 Tennessee was authorized to extend its pipeline from the Buffalo terminus to the New York-Massachusetts state line, and additional extensive territories were thus added to the New York Zone. At the same time, Northeastern Gas Transmission Company (a wholly-owned subsidiary of Tennessee) was authorized to construct a pipeline connecting with Tennessee at such state line, and to deliver gas into New England. Northeastern thereafter purchased gas from Tennessee at the New York-Massachusetts state line. (9 FPC 271) By order issued July 16, 1954, the Commission authorized a merger between Tennessee and Northeastern. As a result of this merger the New England rate zone was established, with the service area of the merged subsid-

[3] Comprised of Hope Natural Gas Company, The East Ohio Gas Company, The Peoples Natural Gas Company, New York State Natural Gas Corporation, and Lake Shore Pipeline Company.

[4] Includes United Fuel Gas Company, The Manufacturers Light and Heat Company, and The Ohio Fuel Gas Company.

[5] Comprising some 25 New England distribution companies and municipalities, which participated jointly in the proceeding.

[6] In addition, a large number of other intervenors, although not presenting evidence on their own behalf, participated in the hearing and have filed briefs herein.

[7] Since a portion of the testimony on the zoning issue was presented at an earlier stage of the hearing, prior to the Commission's April 30, 1959 order of severance, it may be helpful to note that although the bulk of the testimony on this issue is set forth in Transcript Volumes 47 through 69, the direct testimony of Tennessee witness Davis appears in Volume 2, pages 327–334, Volume 3, pages 354–358, 397–414, 421–427, and Volume 20, pages 2794–2800. The cross-examination of witness Davis with respect to this testimony runs from Volume 29 through 34. Further, while the exhibits on this issue range principally from Exh. 78 through 142B, Tennessee initially presented Exhs. 21 and 22 as its zone allocation exhibits, and subsequently modified them with Exhs. 50 and 51, upon which it now relies.

[8] Subsequently, the area of the Southern Zone was enlarged to include the states of Arkansas and Louisiana.

iary becoming the New England Zone (Docket Nos. G–2352 and G–2353, order affirming Examiner's decision of June 15, 1954, 13 FPC 623).[9]

The characteristics of the various Tennessee rate zones may be summarized as follows:

(1) The Tennessee transmission system carries gas from the sources of supply in Texas, from South Texas to the Louisiana boundary where Southern Zone 1 begins. There are no jurisdictional sales from the main pipeline prior to Zone 1.

(2) In Southern Zone I and Central Zone 2, the gas is transported further from points at or near the sources of supply through multiple and parallel large-diameter lines. The largest part of the volumes transported in these two zones is carried forward to other zones.

(3) In Eastern Zone 3, which is a terminal zone ending in West Virginia, and historically the terminus of the original Tennessee system, the gas moves a relatively short distance, in very large volumes, through 20-inch and 24-inch pipelines, to the system's two largest customers (United Fuel Gas Company and Hope Natural Gas Company) and two other customers, who purchase at approximately 100 percent load factor.

(4) In Northern Zone 4, where nearly half of the gas moving into the zone is sold there, the transportation is characterized by large volumes and the sales by high load factor. Through Ohio and as far as Pittsburgh in Pennsylvania, there are multiple and parallel pipelines of large diameter in this zone. However, at Mercer, Pennsylvania the system divides into only two lines, which are thereafter widely separated, one passing into Northern New York at the Zone 5 boundary and the other crossing the state of Pennsylvania to enter Zone 5 at the Pennsylvania-New Jersey boundary.

(5) New York Zone 5 has one long, principally 24-inch line extending across Northern New York State to the Massachusetts boundary, and one 24'' line extending from the New Jersey-Pennsylvania boundary to the New York-Connecticut boundary.

(6) In New England Zone 6, the load factor is the lowest on the Tennessee system, the transmission lines are of smaller diameter, and the volumes are the smallest in the system for any zone. In addition, there are numerous small laterals. (47:4916–18)

Comparative data with respect to load factor, volume of sales and load distribution for each of the six zones is shown in the following table:[10]

Zone	1956 sales	Gas transported for others	Total	Load distribution [1]	Load factor
	Mcf	*Mcf*	*Mcf*	*Percent*	*Percent*
Southern	87,521,128	----------	87,521,128	13.67	74.9
Central	59,508,915	----------	59,508,915	9.29	88.2
Eastern	218,710,078	13,230,168	231,940,246	36.21	99.2
Northern	99,739,602	55,829,332	155,568,934	24.29	101.0
New York	69,283,350	----------	69,283,350	10.82	91.5
New England	36,648,220	----------	36,648,220	5.72	[2] 48.6
Total	571,411,293	69,059,500	640,470,793	100.00	88.6

[1] Ratio of each zone's sales to total system sales.

[2] The New England Intervenors contend that Staff's figure of 48.6 percent for the New England Zone load factor is unreasonably low, as the result of two alleged errors in the Staff computation, as discussed at length on pages 18–21 of the New England reply brief; that if these two errors were eliminated, the computed load factor would actually be substantially higher than 65 percent. This problem will be referred to again at a later point.

[9] Additional extensive territories were added to both the Northern and New York Zones in 1955.

[10] The data set forth in this table is taken from Staff's Exhibits 90 and 97–A, all as set forth at page 53 of Staff's initial brief.

History and Characteristics of the Tennessee System [11]

Tennessee operates one of the largest natural gas transmission systems in the United States. The original pipeline was constructed in 1944 after a finding by the War Production Board that the Appalachian area was in urgent need of more natural gas for the war effort, and after authorization by the Federal Power Commission.

The original system extended from South Texas to West Virginia as a single pipeline of 1,265 miles. The first full year of operations was 1945. In that year the system designed capacity was 200,000 Mcf, and deliveries amounted to 73,564,200 Mcf. Approximately 95 percent of such sales in 1945 were made to two customers in the Eastern Zone—*i.e.*, United Fuel Gas Company, a Columbia subsidiary, and Hope Natural Gas Company, a Consolidated subsidiary. Tennessee's net plant investment in 1945 was $61,768,800, and compressor stations had a total of 60,000 horsepower installed.

The Tennessee system has grown and expanded constantly since that time. Since 1945 Tennessee has approximately doubled the length of its system, expanded its capacity over ten-fold, and increased the number of customers served from the original two to eighty-two as of 1956.[12] The original pipeline was principally a single 24-inch pipeline, 1,265 miles in length. The present system is 2,140 miles in over-all length, and consists of several lines totaling 9,811 miles. At the end of 1956, design capacity was 1,863,000 Mcf, deliveries totaled 638,923,200 Mcf, net plant investment was $909,326,700, and compressor station horsepower was 579,120.

Until the year 1950, all system expansion took place within the general geographic area of Tennessee's original system. The first extension of facilities beyond the Appalachian area took place late in 1950 upon completion of a 382-mile line from Kentucky to a point near Buffalo, New York. In 1951 this line was extended an additional 297 miles across the state of New York to the Massachusetts state line. Deliveries of gas on a limited scale were initiated in September 1951 to Northeastern Gas Transmission Company, Tennessee's then wholly-owned subsidiary, operating in New England. On September 3, 1954, Tennessee acquired all of the facilities of Northeastern, consisting of 533 miles of pipeline system. In 1955 Tennessee completed a 250-mile extension of its system from the Hebron Storage Field in Northern Pennsylvania to connect near Greenwich, Connecticut with the southern terminus of the New England system. This construction completed a 1,000-mile pipeline loop, integrated with underground storage. The first withdrawals of gas from the Hebron Storage Field also occurred in 1955.

The Tennessee system, as it existed in the test year 1956, originates near the United States-Mexico boundary in South Texas and extends in a northeasterly direction 2,200 miles to Northern New England, representing the nation's longest pipeline system. One of its extensions connects with Canadian facilities, terminating at the Niagara River border north of Buffalo, New York. The Tennessee system traverses fifteen states: Texas, Louisiana, Arkansas, Mississippi, Tennessee, Kentucky, West Virginia, Ohio, Pennsylvania, New Jersey, New York, Massachusetts, Connecticut, Rhode Island, and New Hampshire. From a point near the Rio Grande in South Texas into Northeastern Kentucky, the mainline system consists of two, three, or four parallel pipelines. A fifth pipeline follows the Gulf Coast from South Texas to Louisiana and then approaches the main system until their intersection in Tennessee north of Nashville. From

[11] The data set forth at this point is based primarily upon Exh. No. 33.

[12] Deliveries to Tennessee's original two customers, United Fuel and Hope Natural, in 1956 amounted to 37.6 percent of the total system deliveries.

near the Ohio-Pennsylvania border and extending in an easterly direction, the system forms a 1,000-mile pipeline loop in Pennsylvania, New Jersey, New York, Connecticut and Massachusetts. During the test year, gas obtained from some 400 producers located in Texas and Louisiana, including the offshore producing areas in the Gulf of Mexico, flowed downstream along two widely separated supply routes until it reached Compressor Station No. 87, located at the northern end of the Southern Zone.[13]

Tennessee's underground storage operation received its initial FPC authorization in 1952, and injection of gas into Hebron Storage Field in Northern Pennsylvania was commenced late the following year. Service from underground storage was commenced in 1955. Eventually, Tennessee plans to have four storage fields in operation, all located about three-quarters of the distance downstream on the system. The present indicated peak-day deliverability of Tennessee's storage facilities is on the order of 400,000 Mcf per day.

Tennessee's principal activitity is the wholesale transportation and sale of gas as a fuel. It also engages in diversified activities relating to the production, conversion and transportation of hydrocarbons. It produces and markets liquefiable petroleum gases, produces and refines petroleum, markets gasoline and fuel oils, and has entered the petrochemical field through a half-interest in a Houston plant manufacturing butadiene. A subsidiary, Bay Petroleum Corporation, carries on the refining and petroleum products marketing activities of the company. Another subsidiary, Tennessee Products Pipe Line Company, had under construction during 1956 a fractionating plant to separate liquid hydrocarbons. Tennessee also has two other subsidiaries—The Tennessee Life Insurance Company, which owns the company's headquarters building in Houston, and the Ten Ten Travis Corporation, which operates a 1500-car public parking garage in downtown Houston.

Historic Treatment of the Zoning Problem on the Tennessee System

The posture of the zoning issue, as here presented for disposition, can be better understood if attention is initially directed to the historic facts as to how the problem of zone differentials has been handled on the Tennessee system. (Exh. 69)

(1) This history begins with the very first Tennessee rate increase proceeding, in Docket Nos. G–1741 and G–1764, culminating in a rate increase amounting to $11,320,000 annually, which became effective on December 17, 1951, and which was arrived at through settlement proceedings between the company, Commission Staff, and intervenors. (10 FPC 1608, 11 FPC 687, 737) In that proceeding Tennessee proposed that costs be distributed between its zones on the basis of a "hundred Mcf-mile" allocation method.[14] In the ensuing rate settlement conference several of the Tennessee customer companies objected to the effect of that allocation, and the problem of the zone differentials then became the subject of a special conference. The end result was a compromise agreement with respect to the rates to be established for the different zones, which was thereafter approved by the Commission in an order issued on January 21, 1952.[15] In this order the Commission stated:

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[13] A third supply trunkline extending southward from Compressor Station No. 87 to the Louisiana area below New Orleans has subsequently been placed in operation.

[14] This method is similar to the Mcf-mile method which will subsequently be discussed at length in the instant decision.

[15] Columbia counsel Rosan in the course of the instant proceeding described what happened in the G–1741 zoning settlement as follows:

> "And then after the dollars were arrived at, there was a conference of all the customers of Tennessee. And there was a lot of pulling and tugging by various zones. And there were slight adjustments made in the rate to arrive at a compromise that everyone would accept." (29 : 3946–47)

Although there were many conflicting views as to allocations and methods of allocation reflecting broad differences in interest of the various utility purchasers in different zones, the conferees reached unanimous agreement respecting rates for the different zones, it being concluded by all, including the staff of the Commission that the rates agreed upon were fair, equitable and within the realm of reasonableness as a whole and as to each zone. (11 FPC 738)

(2) The next succeeding Tennessee rate case was Docket G–2052, in which an increase of approximately $14,000,000 annually was granted as the result of a settlement which became effective July 28, 1953. (12 FPC 1096) The rate increase proposed by Tennessee in this proceeding was based entirely upon the cost of purchased gas, and the technique adopted was to simply add a roughly uniform amount to the existing commodity cost in each zone. Under the settlement, the commodity charges of the contracted demand and general service rates were increased by 3.3 cents per Mfc in the Southern Zone, 3.6 cents in the Central and Eastern Zones, 3.37 cents in the Northern Zone, and 3.38 cents in the New York Zone. (31:4232)

(3) The next Tennessee rate filing was in Docket G–2252, where an increase of $4,768,000 annually became effective March 1, 1954 as the result of a settlement approved by the Commission. Here again the problem of arriving at a definitive resolution of the zone allocation question was passed over in the settlement. In order to avoid controversy, Tennessee merely proposed to add its claimed incremental costs to the existing rates, which had previously been approved in Docket G–2052. Under this settlement, the monthly demand charge in all zones was increased by a uniform 10 cents per Mcf, for the contracted demand and general service rates and the transportation rates. The commodity charge of the contracted demand and general service rates was increased by .55 cents per Mcf in the Southern Zone, .69 cents in the Central and Eastern Zones, .78 cents in the Northern Zone and .97 cents in the New York Zone. (Tr. 4230)

(4) Subsequent to the Commission authorization of the Northeastern merger in July 1954, service to the New England Zone as such commenced in September 1954, under rates which were fixed for that zone effective September 1. (31:4230–31) These New England rates represented simply a continuation of the rates which had been in effect under the Northeastern tariff for sales in the New England area immediately prior to the merger.[10]

(5) The next Tennessee rate case consisted of an unnumbered filing, under which an increase of $1,134,000 annually, relating to an increase in the Texas production tax, was permitted to become effective as of November 18, 1954, without suspension. (31:4250–51) The result was to add a uniform .25 cents per Mcf to the commodity charge for the contracted demand and general service rates in all zones. (31:4230)

(6) The last Tennessee rate proceeding prior to the instant case was Docket G–5259, filed in November 1954, in which Tennessee sought an annual increase in the amount of $8,616,000, based largely upon increases in its cost of purchased gas. Here again, in an effort to avoid litigation, Tennessee proposed to recoup its increased costs in the form of a uniform 1.9 cents per Mcf increase, to be applied to the commodity charge for the contracted demand and general service rate in all zones. (31:4229–30) However, in

[10] The said Northeastern rates, which were applicable to sales in the New England area prior to the merger, reflected the purchased gas cost paid by Northeastern to Tennessee, at the New York Zone rate level, for gas delivered by Tennessee to Northeastern at the New York-New England boundary line, plus an increment for Northeastern's own operating costs and return on plant.

the course of the hearing in that case the New England intervenors raised the zoning issue and presented a complete case-in-chief on that question, under which costs were allocated among zones on the basis of an Mcf-mile method. This New England zoning proposal was strongly opposed in the G–5259 hearing by Consolidated and Columbia. However, by order issued October 6, 1955 in that proceeding, the Commission severed and deferred further consideration of the zoning problem until the dollar cost of service issues should be tried and decided. This cost of service hearing culminated in a Commission order of October 17, 1957 approving an annual increase in revenue of approximately $7,700,000, effective as of December 15, 1954. In the meantime, Tennessee had made a still further rate filing in the instant Docket G–11980, involving a proposed increase of $24,077,000 annually which became effective, subject to refund on July 14, 1957. In the G–11980 rate filing Tennessee squarely raised the zoning issue. Accordingly, on July 1, 1957, Tennessee filed a motion to dismiss the zone allocation issue in Docket G–5259, contending that the zoning issue should be litigated and resolved once and for all in the instant G–11980 proceeding. All parties agreed to this motion, for the reasons indicated, and the motion was granted by Commission order of September 5, 1957.

It is apparent from the above recital that up to this date the Commission has never previously considered or decided, on the merits, the proper allocation of Tennessee's costs among its zones or the proper zone rate differentials. It is further apparent that the Docket No. G–5259 zone differentials, with some slight modifications, represented basically the zone differentials which were worked out and agreed on by the parties, and accepted by the Commission in 1952 as part of the rate settlement in Docket G–1741; that these zone differentials were thereafter incorporated, with the slight modifications referred to above, in every succeeding Tennessee rate case, because of the desire of the parties to postpone the litigation and final resolution on the merits of this complex and troublesome problem.

In the instant proceeding, however, pursuant to the Commission's order of severance of April 30, 1959, the zoning issue has been fully tried and comprehensively briefed, on the merits. Although the instant Docket No. G–11980, as a result of Tennessee's later rate increase filing in Docket No. G–19983, has now become purely a refund case with respect to the dollar cost-of-service issues, the instant proceeding has nevertheless become the vehicle for final resolution of the zoning question. Whatever allocation method may be here adopted for the allocation of Tennessee's total system costs between its existing zones will be applicable to the Tennessee system for the future—unless and until it may be demonstrated at some later date that a change is required.

The Columbia Theory That the Commission Has Already Determined How Costs Should Be Allocated to the New England Zone

Before proceeding any further, it will be appropriate at this point to dispose of a Columbia theory (emphatically developed at pp. 17–22 of its initial brief in this proceeding) which is designed to suggest that the zoning question has already been previously resolved by the Commission and that accordingly nothing remains to be litigated here. Columbia contends that by virtue of an accounting condition originally imposed upon Tennessee by the Commission in the *Northeastern* merger case,[17] and by language referring to that account-

[17] Order issued July 16, 1954, *In the Matters of Tennessee Gas Transmission Company and Northeastern Gas Transmission Company*, Docket Nos. G–2352 and G–2353, authorizing the merger between Tennessee and Northeastern, 13 FPC 623.

ing condition which the Commission included in its Answer to Motion for Stay, filed January 24, 1959 with the Court of Appeals for the District of Columbia in another proceeding, the Commission has finally disposed of the issue as to how costs should be allocated to the New England Zone; that by the use of this language in such other proceedings, the Commission has made it abundantly clear that Tennessee was not to be permitted to roll in the New England Zone costs and to spread them over its entire system, but instead has already determined that costs incurred by Tennessee within the New England Zone must be assigned directely to that zone, together with joint costs applicable thereto. If we were to accept this Columbia contention, we would have to agree that the precise zoning issue which has been litigated at such length in the instant proceeding has already been decided on the merits and is no longer open to controversy. The mere statement of this proposition is sufficient to reject it.

The accounting condition imposed upon Tennessee in the *Northeastern* merger order, *supra*, provided as follows:

> The Applicant[18] shall maintain in conformity with the Uniform System of Accounts, supplemental accounts in scope and form satisfactory to the Commission designed to show separately: (a) the actual expenses and charges which would be involved in any determination of Applicant's cost of service for the New England Zone formerly served by Northeastern, and (b) all applicable expenses and charges properly included in Applicant's system cost of service which would be involved in determinations of allocations thereof between the several zones of service.

It seems perfectly clear that by inserting this accounting condition in the Northeastern merger order the Commission intended merely to insure that all the possibly relevant and useful data which might ultimately be needed to determine which zoning allocation method should be adopted would be available whenever the Commission should decide in some future rate proceeding to finally come to grips with that problem on the merits. The outline set forth immediately above of the steps which have occurred in the historic treatment of the zoning problem on the Tennessee system makes it clear that when the Commission issued its Northeastern merger order of July 16, 1954, it was perfectly aware of the fact that there was still a hotly disputed and unresolved issue on the Tennessee system as to whether costs should be allocated among the various zones under an Mcf-mile method, or under a zone-by-zone approach. The Commission was further aware of the fact that in the early part of 1954, in connection with a Tennessee rate proceeding in Docket No. G–2252, certain customer companies and the Commission staff were requesting Tennessee to include a definitive allocation in its next rate filng; that Tennessee had in fact complied with this request in its next rate increase filing of April 1954, in Docket No. G–2434, but that as a result of the settlement of the latter proceeding the zoning question remained still unresolved. It is inconceivable that under all these circumstances the Commission would have given any serious thought to making a final disposition of this troublesome zone allocation issue in the Northeastern merger case by the simple adoption of the accounting condition referred to above, and in the context of a situation where the zoning issue had not even been litigated in that proceeding.

In this connection, it is important to note that when the Commission subsequently, in the Tennessee rate proceeding in Docket No. G–5259 and in the instant Docket No. G–11980 proceeding, issued interim orders requiring Tennes-

[18] The Applicant was Tennessee.

see to make available to all parties certain described data relating to the New England Zone, based upon the accounting condition in the Northeastern merger case, the Commission was careful to insert a *caveat* making it clear that it did not thereby intend to dispose of the zoning issue on the merits. In the Commission Order Directing the Furnishing of Data, issued in Docket No. G–5259 on November 17, 1955, paragraph (C) of the order provided:

> Nothing contained in this order shall be construed as a determination by the Commission of what relevancy such data may have in the disposition of the issues in this proceeding.

The identical *caveat* was inserted as ordering paragraph (D) in the Commission's Order Denying Appeal, issued November 1, 1957 in the instant Docket No. G–11980. Finally, in its Order Denying Motion for clarification, issued December 31, 1957 in the instant proceeding, the Commission stated:

> For the purposes of this order to Tennessee, it is understood that the cost data and allocation thus presented will not be construed to represent Tennessee's position on cost data or allocation.

In an effort to buttress its theory with respect to the significance of the accounting condition in the Northeastern merger order, Columbia cites certain language which was included in an Answer to Motion for Stay filed by the Commission on January 24, 1959 in the U.S. Court of Appeals for the District of Columbia, in the *Manufacturers Light and Heat Company* case, Docket No. G–15826 (Case No. 14897), involving the lawfulness of a Commission order authorizing Tennessee to provide Peaking Service in the New England Zone during the 1958–59 heating season. In that Answer the Commission referred to a concern expressed by the petitioners in that proceeding that costs properly chargeable to the New England Zone would be improperly loaded by Tennessee on the other zones. The instant Columbia brief quotes and emphasizes a selected statement from that Answer as follows:

> As a matter of fact, the Commission has already taken care to insure that it can avoid doing what petitioners assume it will do. This occurred at the time of the merger with Tennessee of Northeastern Gas Transmission Company, Tennessee's wholly-owned subsidiary which had previously served New England. In approving that merger, the Commission affirmed and adopted the examiner's decision imposing conditions which would enable the Commission in the future to determine and fix costs of service in the New England zone separately notwithstanding the merger * * *.

In order to clearly understand the meaning and significance of this Commission statement, made in its Answer filed with the Court of Appeals, it is important that it be considered *in context* with the language which the Commission used immediately preceding; and immediately following the statement quoted in the Columbia brief. The Commission language quoted in the Columbia brief appears on page 7 of its Answer. At page 5 of the same Answer the Commission stated:

> *If* petitioners' contentions as to the proper method of allocation prevail, the Contract Demand rates in Zones 2, 3, and 4 will be relatively lower than those proposed by Tennessee, and the General Service rates in Zone 6 will be relatively higher. If that results in a rate for the Peak Service of more than the 90 cents per Mcf which Tennessee is now collecting (subject to possible refund), the resulting deficiency in Tennessee's total revenues will be its own fault and will afford no basis whatever for departing from an otherwise proper basis of allocation or for declining to fix rates for each zone and class of service on the basis of cost of service so determined and allocated. [Emphasis supplied.]

At page 12 of the same Answer the Commission stated:

> The analysis already made of petitioner's allegations in support of their claim of aggrievement has shown that those allegations both depend upon the possibility that Tennessee's Contract Demand rates in Zones 2, 3, and 4, under which petitioners make their purchases, may be fixed too high, in order to offset Tennessee's too-low Peak Service rate, and, if so, that the refunds to petitioners will be reduced. *But that can occur, if at all, only by force of a Commission order in the rate proceeding under Section 4(e) of the Gas Act, which is now pending upon increased rates filed by Tennessee, Docket No. G–11980. This being true, the obvious conclusion is that in that proceeding, if anywhere, will petitioners find their remedy. There, where the rates they are to be charged will be fixed, is the proceeding in which, if anywhere, their contentions as to the proper method of allocating total costs of service between zones should be presented.* [Emphasis supplied.]

The full Commission statement, as quoted above, reveals clearly that the Commission was there merely informing the Court of Appeals, in unambiguous language, that the question as to the proper method for allocation of costs between the Tennessee zones was still unresolved on the merits; that this issue would be finally resolved in the instant G–11980 proceeding; that whatever costs the Commission might ultimately determine in Docket G–11980 as the proper costs to be allocated to Zones 2, 3, and 4 would be charged to those zones, *and no more;* and that whatever costs the Commission should determine in the G–11980 proceeding as the proper costs to be allocated to the New England Zone would be charged to that zone, *and no less.*

Definition of the Problem to be Considered on the Merits Here

We therefore proceed now to a consideration of the zone allocation question on its merits. The zone allocation question in its broadest sense necessarily involves a number of subsidiary problems, such as normalization of sales during the test year, classification of costs between demand and commodity elements, and assignment of demand responsibility as between customers. While all of these subsidiary elements raise problems which must be resolved, and which therefore will be considered at length in this decision, the key problem is that of determining a proper and equitable *basic* method for allocating costs among the various zones for the ultimate purpose of determining rates within the zones. In this connection, as will be seen shortly, although five different zone allocation presentations have been made in this case, the critical issue to be resolved here is whether Tennessee's costs are to be allocated on the basis of system-wide average costs (on a mileage basis), or whether segregated zone costs are to be employed.[19]

Although these five allocation presentations differ in various respects, they may properly be grouped for purposes of discussion and comparison into two basic allocation method categories, as follows:

(1) *The Mcf-Mile Method*—advocated by Tennessee, the Commission Staff and the New England intervenors. This was the method adopted and approved by the Commission in the landmark *Northern Natural* zoning case, *In the Matter of Northern Natural Gas Company*, 14 FPC 11, Op. No. 281 (1955), affirmed in

[19] It should be noted at the outset that the controverted issue here relates primarily to the allocation of *transmission* costs. There is no dispute as to the method to be followed for the allocation of *production* costs, including both natural gas production and gathering expenses, and purchased gas costs. All parties agree that such costs should be allocated on a straight volumetric basis.

Interstate Power Company, et al. vs. *Federal Power Commission* (CCA 8, 1956), 236 F. 2d 372. Its rationale is that "unless other circumstances are present which outweigh the importance of the length of transmission required to effect delivery, the distance factor is the prime determinant of the cost of rendering service." (14 FPC 24) Under the Mcf-mile method all of the pipeline's transmission costs are rolled-in on a system-wide basis. Such costs are then, after classification between demand and commodity elements, allocated among zones on the basis of volume (both peak day and annual) and miles of haul. The three variations of the Mcf-mile approach presented in this proceeding are as follows:

(a) The New England intervenors employ the straight Mcf-mile method, without adjustment.

(b) Tennessee allocates half of the transmission costs on a mileage basis, utilizing the Mcf-mile method—and half on the basis of historical factors, utilizing the Docket G–5259 rate levels applied to 1956 deliveries.[20]

(c) The Commission Staff employs the Mcf-mile method. However, the costs thus allocated to the New York and New England Zones are then adjusted upward by utilizing the higher dollar amounts of revenues at the Docket G–5259 rates as the number of dollars to be recovered for those two zones. The differences between the original allocated cost and the revenue level at the G–5259 rates in these two zones are considered as excess revenues to be distributed to the other four zones and to the transportation services as a credit to their allocated cost of service.

2) *The Zone-By-Zone, or Zone-Gate Method*—advocated by Columbia and Consolidated. This is a *segregation of property* approach, which earmarks certain zone costs, but also makes extensive use of certain systemwide factors. It is a combination of a segregation and cumulative cost allocation method, in that it attempts to segregate costs in a particular zone to which are added the cumulatively allocated costs of all *upstream* zones. The two variations of this approach are as follows:

(a) Consolidated employs the straight zone-gate method.

(b) Columbia utilizes a zone-gate, capacity-credit method. Its essential difference from the Consolidated approach lies in the fact that, in classifying fixed costs between demand and commodity, Columbia departs from the Commission's *Atlantic Seaboard* (Op. No. 225) method, and instead allocates all of the fixed costs to demand. It then uses a "capacity credit adjustment" to shift a portion of the fixed costs to "interruptible" sales.

Throughout the briefs submitted by Columbia, Consolidated, and other supporters of the zone-gate allocation method runs the theme, expressed in one form or another, that under the zone allocation pattern which has been in effect on the Tennessee system up to this time a substantial portion of the New England Zone costs have been shifted to the Central and Eastern Zones, in which they operate, and that they have accordingly for years been subsidizing the New England Zone.[21] On the other hand, the New England intervenors contend that under the existing allocation pattern the New England Zone has for years been carrying more than its proper share of the total system costs.

The fact is, of course, that a comparison of the total costs allocated under each of the different allocation methods here proposed can be used to demonstrate that each of the different zones, including the New England Zone, has up to this date been carrying too large or too small a portion of the total

[20] Tennessee employed this method in its instant Docket G–11980 rate filing.

[21] As noted previously, the allocation pattern in effect up to this time has reflected, basically, the zone differentials which were originally agreed to by the parties as a part of the Docket G–1741 rate settlement in 1952.

system costs—depending upon which particular allocation method is here approved. It is thus clear that the conflicting arguments referred to above assume the answer to the very issue which must be decided in this proceeding—*i.e.*, which one of the proposed zone allocation methods is most reasonable and fair for the Tennessee system, and should therefore be adopted here.

The contention that the Central and Eastern Zones have up to now been subsidizing the New England Zone has merit only if we conclude that the correct way to determine the portion of total system costs properly chargeable to each zone is under a method which treats each zone as a separate and independent operating entity, and which therefore employs a segregation of facilities and costs for each separate zone. This contention would not be meaningful, however, if we conclude instead that the Tennessee system should be treated as an integrated entity, with all zones being required to share in both the benefits and the burdens of the entire systemwide operation.

The Consolidated "Burden of Proof" Theory

Consolidated has devoted a major portion of both its initial and reply briefs in this proceeding to a narrow "burden of proof" theory not advanced by any of the other parties. Consolidated contends that as a result of the lapse of time, plus the pendency of the new Tennessee rate increase proceeding in Docket G–19983, any future rate fixing and any determination of the proper zoning method to be adopted for the Tennessee system for the future should take place in the G–19983 proceeding; that the instant G–11980 proceeding should be treated for all purposes, *including zoning*, as merely a refund case for a locked-in period.

In making this contention, Consolidated stresses that by its filing in G–11980 Tennessee has sought to change the G–5259 revenue level basis "which was the basis historically agreed upon by Tennessee and its customers and approved by the Commission, prior to Tennessee's filing" (initial brief, p. 22). It therefore argues that the only zone allocation question which should be decided in the instant proceeding is the narrow question whether, for refund purposes only, Tennessee has sustained its burden of proof in justifying a departure from the existing "historically agreed" G–5259 revenue level basis of allocation, to the 50 percent Mcf-mile and 50 percent historical revenue basis method employed in its G–11980 rate filing. Consolidated contends that this burden could only be sustained by establishing that the existing historically agreed G–5259 zone rate structure is unduly discriminatory or preferential or otherwise unlawful; that this has, in fact, not been satisfactorily established by Tennessee in this proceeding; that accordingly this leaves the G–5259 allocation pattern in force for the purpose of any order to be issued in the instant G–11980 proceeding.

In making this recommendation, Consolidated adheres to its view that its own proposed zone-gate allocation method should be used for *prospective* rate fixing, but concludes that the existing "historically agreed" G–5259 revenue level basis of allocation should be used for refund purposes in the instant case, in order to assure Tennessee of a fair return retroactively. Consolidated notes, in this connection, that if its own proposed zone-gate method were adopted retroactively for refund purposes in the instant proceeding, Tennessee would be left to shoulder a deficiency amounting to $3,400,000, on the basis of the Staff's proposed cost-of-service; that such a deficiency would be caused not by any defect in the zone-gate allocation method, but by the inability of any pipeline company under the Natural Gas Act to raise rates in any zone *retroactively* to compensate for any change in cost allocation for refund purposes.[22]

[22] It may be noted here that, except for the zone-gate allocation method, the use of the G–5259 allocation pattern as here advocated by Consolidated would produce the lowest aggregate cost allocation to Zones 3, 4, and 5, where Consolidated purchases its gas from Tennessee.

The Consolidated "burden of proof" theory, as thus presented, is based upon an approach which gives an air of sanctity to the G–5259 allocation pattern, and which suggests that we are not at liberty *de novo* in this proceeding to determine which of the alternative allocation methods should properly be adopted for the Tennessee system. However, this entire argument, and the foundation upon which it rests, ignores the factual history of the treatment of the zone allocation problem on the Tennessee system, as outlined in some detail at an earlier point in this decision. As there pointed out, the G–5259 allocation pattern represented simply a continuation and reflection (with some minor modifications) of the compromise distribution of costs between zones which was originally worked out by the parties in the G–1741 rate settlement in 1952, and which was carried along, by common consent, through every succeeding Tennessee rate case in order to defer coming to grips on the merits with the troublesome zoning problem.

It is thus clear that the Commission, up to this date, has not previously considered or decided the zone allocation question on its merits—and that the instant G–11980 proceeding has been selected as the case in which this difficult and long-standing controversy would be finally faced up to and resolved once and for all. Consistent with this objective, a tremendous amount of time and effort has been devoted by all parties to the most comprehensive and exhaustive trial and briefing of the zone allocation issue in this case. The adoption of the Consolidated "burden of proof" theory would, of course, have the effect of completely negating this entire objective. It would, in the light of the circumstances outlined above, amount to complete administrative frustration and would be contrary to the public interest. There is nothing in either the law or the facts which compels the Commission to here adopt so self-defeating or limiting a position, and this Consolidated recommendation is accordingly rejected.

Description of the Alternative Zone Allocation Proposals

We turn now to a detailed examination, on the merits, of the different basic zone allocation methods presented by the parties in this proceeding.[23]

(1) *The Mcf-Mile Method*

With respect to the allocation of transmission costs the Staff, the New England intervenors and Tennessee (except for the 50 percent which Tennessee allocated according to the historical revenue pattern) have all employed the Mcf-mile method as adopted by the Commission in the Northern Natural case, Op. No. 281.[24]

The mechanics of the Mcf-mile method, as thus applied, are as follows: The daily demands[25] and annual deliveries for each delivery point were multiplied by the miles of haul to each delivery point to obtain total demand and commodity

[23] Such subsidiary problems as (a) whether demand costs should be allocated on the basis of a three-day peak, or on the basis of average billing demands, and (b) the manner in which costs should be allocated to Seller's Option (SO), Storage (SS–5), Peak (PSG), and Transportation Service, will be considered at a later point.

[24] Underground storage costs were included with transmission costs for the purpose of such Mcf-mile allocation. Unlike the other parties, Staff witness Blair placed *administrative and general expenses* related to the transmission and underground storage functions in a separate "Group C", which he allocated among zones on a straight Mcf demand and volumetric basis, giving no effect to the mileage factor. He explained that, in this regard, he had simply followed the Commission's treatment of this item in Op. No. 281; but that if he were following his own judgment in the matter he would have included those costs in the Mcf-mile allocation.

[25] Based upon average billing demands in the case of Tennessee and the New England intervenors, with imputed demands for the flat rate schedules—whereas Staff based its computation of daily demand upon a three-day peak. This particular controversy will be discussed in detail at a later point.

Mcf-miles for each zone. In the case of *sales* volumes the miles of haul were measured from an average point of receipt of gas, 814 miles southwest of Station 87, to each point of delivery. For volumes transported for others (Transportation Service), miles of haul were measured from the point of actual receipt of gas to each delivery point. The total system-wide costs to be allocated under the Mcf-mile method were classified 50 percent to the demand category and 50 percent to the commodity category. The demand portion of such costs was then divided by the total demand Mcf-miles for the entire system, to obtain the system-wide average cost per demand Mcf-mile. This unit demand cost was then multiplied by the total number of demand Mcf-miles for each zone to obtain the demand cost allocated to each zone or class of service.

The same general procedure was followed with respect to the commodity portion of the costs allocated under the Mcf-mile method. Such commodity costs were divided by the total commodity Mcf-miles to obtain the system-wide average cost per commodity Mcf-mile. This unit commodity cost was then multiplied by the number of commodity Mcf-miles for each zone to obtain the commodity cost allocated to each zone or class of service.

The Mcf-mile method thus applies system-wide average unit costs on a mileage basis, assigning the same cost of transporting an Mcf of gas 100 miles, whether the transportation be in West Virginia, Pennsylvania, New York or Massachusetts. It makes no attempt to separate out and identify with specific zones such items as operating or maintenance expenses, plant investment, taxes, depreciation, or return.

As noted at an earlier point, the New England intervenors employ the straight Mcf-mile method, without adjustment. The Staff, on the other hand, recognizes the existence of a special problem resulting from certain unfavorable characteristics inherent in the New England and New York zones, with respect to load factor, load distribution, and volumes of gas (*i.e.*, pipe size). The Staff method accordingly includes an upward adjustment (which will be discussed at a later point) to the costs allocated to those zones under the straight Mcf-mile method, to reflect and give weight to these factors.

Tennessee employs a combination of both the Mcf-mile method, applied to half of the system-wide transmission costs, and a historical revenue level basis applied to the other 50 percent of transmission costs—thus giving equal weight to distances and historical factors. That part of the allocation based on historical factors utilizes the Docket G–5259 rate level applied to 1956 deliveries, classified between demand and commodity, after eliminating the production cost component from the commodity charge in the sales rate.

The mechanical steps for this portion of the allocation on the basis of historical factors were as follows:

(a) The first step was to compute the annual Mcf demands for each rate zone and for transportation of gas for others. These annual Mcf demands were derived as follows: The sum of the actual monthly billing demands for each of the 12 months of 1956 for rate schedules containing a demand charge, plus the imputed billing demand for sales made under flat rate schedules, was obtained.[28] This sum was divided by 12 to obtain the average billing demand, and the result was multiplied by 365 to derive the annual Mcf demands.

(b) The annual Mcf demands, as thus obtained, were multiplied by the Docket G–5259 unit demand rates in each zone and for each transportation service to obtain the historic demand revenue level.

(c) The production component of the G–5259 commodity rate was deducted from the total commodity rate to arrive at the "delivery" component in such

[28] The imputed demands were predicated on the load factor inherent in each of the flat rate schedules.

rate, representing the transmission costs contained therein. The historic commodity revenue level was then obtained by multiplying the delivery component in the G–5259 commodity rates in the various zones by the actual Mcf of deliveries for such zones in 1956.

(d) Next, the total transmission costs to be allocated on the historical revenue level basis were allocated to demand and delivery in the same relationship or ratios as the total 1956 computed historic demand and delivery revenues bore to the total 1956 computed historic transmission revenues.

(e) The final step consisted of distributing the total thus allocated to delivery among rate zones and to transportation service in the same relationship as the 1956 computed historic delivery revenues had been distributed; and the portion thus allocated to demand was distributed among rate zones and to transportation service in the same relationship as the 1956 computed historic demand revenues had been distributed.

The demand costs obtained under the Mcf-mile method for each zone and class of service were finally added to the demand costs thus obtained on the basis of the historic revenue pattern, to arrive at the total demand cost for each rate zone and class of service. Similarly, the transmission commodity cost derived under the Mcf-mile method for each rate zone and class of service was added to the commodity cost obtained on the basis of the historic revenue pattern, to arrive at the total transmission commodity cost for each rate zone and class of service.

(2) *The Zone-gate Method*

The zone-gate method, advocated by Consolidated and Columbia, is based on the underlying principle that each zone should be treated as a separate operating entity, with the costs segregated by zones. Consolidated witness Learned described this method in his direct testimony as follows:

> A. The best way to determine the actual cost of gas sold in each zone in a system having the characteristics I have just described is to (1) determine the direct costs arising in or prior to the zone nearest the source of supply, (2) determine the system costs allocable to the first zone, (3) allocate the direct costs arising in or prior to the first zone as between sales in that zone and the remaining zones, and (4) follow a similar procedure with each subsequent zone until the terminal zone is reached. This zone-by-zone method of cost determination avoids burdening purchasers of natural gas in zones much closer to the source of supply and requiring only a portion of the use of the pipeline, with any part of the cost of service which is not related to the delivery of gas in zones closer to the source of supply. For example, a customer located in a zone nearer to the source of supply should not contribute to a rate of return on plant which is in no way used to furnish service to the zone nearer to the source. Conversely, any method of averaging direct transmission costs together and spreading them over the system on some basis such as Mcf miles does impose upon the zones nearer to the source of supply a part of the direct cost of serving only the zones more remote from the source of supply in a system having the characteristics of the Tennessee system. (47:4918–9)

Consolidated in this proceeding advocates the adoption of a straight zone-gate method, which it applied as follows:

(a) First, a determination was made of those costs which are directly or actually incurred within the zone nearest to the source of supply—*i.e.*, the Southern Zone.

The direct costs thus found to be "incurred" within the Southern Zone were allocated as between deliveries in that zone and the remaining down-stream

zones. In making this allocation, transmission fixed expenses were first classified 50 percent to demand and 50 percent to commodity, and transmission variable costs were classified as commodity. The direct transmission costs classified as demand were allocated between sales and deliveries made within the Southern Zone and the gas transported beyond that zone in proportion to the average three-day peak.[27] The direct transmission costs classified as commodity were allocated between the sales and deliveries made within the Southern Zone and the gas transported beyond that zone in proportion to annual volumes.

(b) Certain other types of costs were identified as "joint" (system-wide) costs and distributed between all six zones as follows: (1) gas supply and gathering costs, and products extraction costs were classified as commodity costs and allocated among the zones in proportion to the annual volume of gas sold or delivered within each zone; (2) direct underground storage costs were classified as demand costs and allocated among the zones in proportion to the average three-day peak within each zone; (3) administrative and general expense was allocated to each zone essentially in proportion to the supervised expenditures within each zone; (4) distribution operation expenses were allocated in proportion to the number of meters within each zone, and distribution maintenance expenses were allocated in proportion to the gross investment within each zone.

(c) The final step was to combine direct costs allocated to the Southern Zone with that portion of "joint" system-wide costs assigned to that zone, to produce the total cost allocated to that zone under the zone-gate method.

(d) A similar procedure was employed for each subsequent downstream zone until the terminal zone (New England) was reached.

The net result of the zone-gate method is that no zone is made to bear any portion of the costs and burdens of the zones downstream from it. At the same time the New England Zone, as the terminal zone, is charged with an allocated portion of the costs of all upstream zones, but is not allowed to pass on to any of the other zones any portion of the costs "incurred" in its own zone.

Columbia employs the same basic zone-gate approach. However, Columbia applies the method in a much more complicated manner as a result of its adoption of the "capacity-credit" technique as a substitute for the Commission's *Atlantic Seaboard* method for classifying fixed costs between demand and commodity. This capacity-credit technique will be discussed in detail at a later point.

Columbia summarizes its allocation of transmission costs under the basic zone-gate method as follows:

> *Field and Southern* Zone transmission facilities are used jointly to serve all customers in all zones. Mr. Nissel therefore determined the cost of service incurred in such zone and allocated it among all six zones. * * *
>
> *Central Zone* facilities, as well as Station 87 which is between the Southern and Central Zones, are used jointly to provide service to all customers north of Station 87. * * * Transmission plant located in the Central Zone is used to serve all zones except the Southern Zone, which is, therefore, omitted from the allocation of related costs. * * *
>
> *Eastern Zone* facilities and Compressor Station 117 (located between the Central and Eastern Zones) are used exclusively to serve customers in the Eastern Zone. * * * Eastern Zone facilities are not used to provide service to any customers outside the Eastern Zone. * * * Costs incurred in the Eastern Zone are, therefore, charged in full to that zone. * * *
>
> *Northern Zone* facilities are used to deliver gas to numerous delivery points within the zone, as well as to the New York Zone. * * * None of

[27] Consolidated used a three-day peak consisting of December 24, 25, and 26, 1956.

the transmission facilities in the Northern Zone are used to move gas to customers in the Southern, Central, or Eastern Zones. * * * Thus transmission costs incurred in the Northern Zone are the responsibility of customers in that zone and in the New York and New England Zones. Costs are therefore, shared among these three zones. * * *

New York Zone facilities are used exclusively to deliver gas to customers in the New York Zone, and to the New England Zone. * * * Accordingly, the New York Zone and the New England Zone should share transmission costs incurred in the New York Zone. * * *

The New England Zone is in a position comparable to the Eastern Zone in that facilities located therein do not serve any other zone. All transmission costs incurred in the New England Zone should be assigned to that zone. (Columbia initial brief, pp. 27–31)

At the outset it is important to recognize that there are "pluses" and "minuses" with respect to each of the varying and conflicting zone allocation methods proposed in this case, and that none of these methods are free from problems or difficulties. As realistically noted by Tennessee:

An argument can be made for a uniform rate for all customers * * *. An argument can also be made for different rates for each customer based on the "cost" incurred in serving each customer. An argument can be made, as Columbia and Consolidated do, for segregating "costs" within a geographical area. An argument can be made for rates based on mileage. An argument can be made for rates based on historical differentials. An argument can be made for rates based on a combination of mileage and historical factors. Something can be said in favor of each of such methods of allocation or rate-making. The difficulty lies in selecting the method. No one method can lay claim to being the "right" method * * * the selection of the method of allocation to be used is bottomed on fairness and the exercise of judgment. (initial brief, pp. 10–11)

The Supreme Court recognized this inherent characteristic of cost allocation problems in *Colorado Interstate Gas Co.* 3 FPC 32, 324 U.S. 581 (1945), as follows:

Allocation of costs is not a matter for the slide rule. It involves judgment on a myriad of facts. It has no claim to an exact science, Hamilton, Cost as a Standard for Price, 4 Law and Cont. Prob. 321. But neither does the separation of properties which are not in fact separable because they function as an integrated whole. (324 U.S. at 589) * * *

These circumstances illustrate that considerations of fairness, not mere mathematics, govern the allocation of costs. (324 U.S. at 591)

Similarly, the United States Court of Appeals for the Tenth Circuit in a subsequent case involving the same company, *Colorado Interstate Gas Co.* v. *F.P.C.*, 209 F. 2d 717, at 726 (1953), stated:

* * True, it did say that neither method was entirely satisfactory, but the same could be said with respect to any method which might be proposed. Mathematical exactness in the apportionment of cost is an impossibility. Because a method may have some infirmities does not of itself condemn it as a proper method. It is the duty of the Commission to select that method which in its considered judgment more nearly reaches a just and sound result.

In approaching the problem of determining here which of the proposed allocation methods should be adopted for the Tennessee system, each of the alter-

native allocation methods has been measured against the following basic requirements:

(1) The method selected should assign a fair share of the total system cost of service to each of the zones.

(2) The method selected should be a practical one. It should not be so complex as to require long, tedious studies involving speculations and assumptions, but rather should be a method which can be expeditiously applied to facts quickly ascertainable.

(3) The results reached, through applying such method, should make sense.

As earlier noted, the threshold question in this proceeding is whether system-wide average costs, on a mileage basis, are to be employed, or whether segregated zone costs should be employed. Despite the numerous arguments and counterarguments advanced here, and the plethora of problems requiring detailed analysis, the ultimate determination to be made comes down to a choice between two basic philosophies or approaches:

(1) The philosophy that the Tennessee system is a single, integrated pipeline system, operated as a single entity, with each part of the system contributing to every other part; that accordingly, although customers closer to the source of supply should pay less than customers located father away from the source, all customers, as customers of a single, integrated pipeline system, shoulld pay on the basis of average system-wide costs for each mile of transmission.

(2) The conflicting philosophy that costs should be segregated by zones so that the customers in each zone would be treated as if they were customers of separate operating companies. This approach emphasizes the fact that the unit cost of transmission varies in different areas, and insists that an appropriate allocation method must give specific zone by zone effect to such differences in cost.

This zone-gate approach was expressed by Consolidated witness Learned as follows:

> In general, the purpose of an allocation is to determine, as closely as possible, the actual cost incurred for the benefit of each of the zones and the non-jurisdictional customers, *the same as if each zone were a separate company or purchaser*. (47:4914) [Emphasis supplied.]

Similarly, Columbia witness Nissel stated:

> In the cost of service study presented in Exhibit 85 each zone is treated *as a separate operating entity*. (47:5203) [Emphasis supplied.]

Defects in the Zone-Gate Approach

The difficulty with this approach is that it is inconsistent with the basic principles on which Tennessee's integrated system was designed and is actually operated. It is unrealistic to ignore the fact that the entire nature and characteristics of the service which is now available to *all* customers on the Tennessee system, and of the potential service which will be available to them in the future, is intimately tied to, influenced and governed by the nature and characteristics of Tennessee as a single, integrated system—and *not* by the nature and peculiar characteristics of separated and segregated bits and pieces of that system, standing by themselves. Obviously, if the Tennessee system had remained static in the limited form of its original system, which ended in West Virginia (the present Eastern Zone), instead of expanding as it did into other areas and other markets, the nature and characteristics of the service available to the Eastern Zone and to other upstream areas would have had little relation to the facts as we know them today.

The fatal defect in the zone-gate approach is that it is so preoccupied with the "phenomena" occuring within a particular zone (the limits of which, as will be later developed, are arbitrarily established) that it ignores the over-all picture and thus loses the ability to relate the part (*i.e.*, the zone) to the whole (*i.e.*, the system-wide operation). The zone-gate method, in effect, represents a one-way street. It shifts a portion of the costs incurred in upstream zones to the downstream zones—but it fails to shift to such upstream zones any on the downstream zone costs, in spite of the fact that the downstream operations on an integrated system are part of an integrated operation, in which all parts of the system are operated for the mutual benefit of the entire system.

The zone-gate method violates the sound regulatory principle which requires "equal treatment for customers receiving equal service".[28] All customer companies on the Tennessee system are buying a similar service, regardless of the zone in which they happen to be located—*i.e.*, the delivery of a stated volume of natural gas, under certain conditions of take as spelled out in the contract. Yet under the zone-gate method customers in the downstream zones, such as the New England Zone, are penalized not on the basis of any significant differences in the type of service which they seek and purchase from Tennessee, but rather on the basis of fortuitous circumstances over which they had no control—such as the time of construction and the time when the pipe was placed in service,[29] the terrain in which the pipes are laid, the variation in rights of way costs in different areas, the size of the pipes, and many other variations. By contrasts, the Mcf-mile approach avoids placing undue emphasis upon these fortuitous differences, and does not attempt to give undue advantage to any part of the system or group of customer companies merely because, through some quirk of time, terrain, sizing or engineering design, efficiency or executive judgment, it may be argued that the cost to serve that particular area or group is less than that for the remainder of the system.

The service rendered by a natural gas pipeline consists of two basic elements: (a) the supply of gas, and (b) the transportation of gas. All parties to this proceeding are in agreement that gas supply should be considered on an unsegregated basis. Thus, in all of the allocation methods here presented gas supply expenses are allocated in the same manner—averaging the cost of all gas purchased by Tennessee, and charging each customer such average cost. This approach follows the Commission's long-standing general practice to roll-in the cost of gas from all sources for allocation purposes—and to reject the contention that it is necessary or desirable to attempt to determine just what gas goes to each of the several customers and to charge each customer with a gas supply cost based upon the actual cost of that particular block of gas.[30] It would appear that the same considerations which justify the application of the principle of "uniform rates for the same service" to the *gas supply* element of the service rendered by a pipeline apply similarly to the element of *gas transportation.*

The basic principles which should be controlling here are helpfully indicated in *Battle Creek Gas Company* v. *Federal Power Commission*, 281 F. 2d 42 (CADC, 1960). In that case an interstate pipeline, Trunkline Gas Company,

[28] *Battle Creek Gas Company* v. *Federal Power Commission*, 281 F. 2d 42 (CADC, 1960).

[29] Which provides room for cost variations resulting from such factors as inflation, fluctuations in the supply and demand of labor and material, and changes in the art.

[30] See *In the Matter of Panhandle Eastern Pipe Line Company, et al.*, 10 FPC 185, 192 (1951); *In the Matter of Trunkline Gas Company, et al.*, 21 FPC 704, 711 (1959), affirmed in *Battle Creek Gas Company* v. *Federal Power Commission, supra; In the Matter of El Paso Natural Gas Company*, Op. No. 326, 22 FPC 260, 277–78 (1959), and Opinion and Order Denying Rehearing, Op. No. 326–A (Oct. 1959), 22 FPC 659.

applied for a certificate authorizing it to expand its gas purchases in the Gulf of Mexico, to expand its pipeline capacity by increased pumping and partial looping of the pipeline, and to construct new lines from Tuscola, Illinois, to the Michigan-Indiana border near White Pidgeon, Michigan, where 135,000 Mcf per day of the increased gas supply was to be sold to one customer, Consumers Power Company. Trunkline proposed to fix a price for the new gas to be sold to Consumers, sufficient to cover the entire cost of the expansion project on an incremental basis, so that Consumers and its customers would bear the entire cost of the expansion program. The Commission order, however, adopted a method under which all the costs of the expansion program up to Tuscola were "rolled-in" with the other system-wide costs of Trunkline, and were included in the cost basis considered in fixing the rates of *all* of Trunkline's customers—while the costs of the pipeline from Tuscola to the Michigan-Indiana border were treated as incremental costs and charged directly and solely to Consumers.[21] On appeal, intervenor Battle Creek Gas Company contended that the Commission's adoption of the rolled-in cost allocation method put an unfair burden upon it and other customers, who would thus be required to bear the cost of the expanded facilities but would allegedly receive no benefit from them.

The Court of Appeals upheld the Commission's adoption of the rolled-in allocation method, stating:

> There are two basic and potentially divergent methods of allocating new asset costs to be reflected in a utility's rate structure. The first recognizes that a gas pipeline of this sort is not just a collection of discrete pieces and parts, but an integrated system serving all of its customers. Applying this approach the cost of the various assets of the system are collected or "rolled in" to arrive at cost of the entire system which is then pro-rated among all of the customers by one of the several rate-making mechanisms not here involved.
>
> *This method has many apparent advantages and the Commission has repeatedly stated a general preference for it wherever it may equitably be used. It avoids the onerous administrative burden of having to assign a different portion of the cost to each of a large number of customers.* It results, if all other factors be equal, in all customers paying the same price for gas taken from the pipeline at the same point, and recognizes that all customers enjoy the benefits of having the whole gas gathering and pipeline system. (281 F. 2d 46) [Emphasis supplied.]

It is of interest to note that the Court, in the very next paragraph, recognized the basic complaint made here by Columbia and Consolidated against the Mcf-mile method, in the following language:

> *The rolled-in rate method is generally disadvantageous, however, to old customers of an expanding pipeline. The cost of new facilities and new gas historically has risen steadily, and a rolled-in rate requires old customers to pay a higher price and bear part of the cost of an expansion from which they receive little visible increase in service.* But conversely, use of the rolled-in approach ensures that two otherwise similar customers will not pay radically different prices for commingled gas coming from the same pipe, merely because one happens to have been receiving the service longer than the other. *Use of the rolled-in method thus serves the interest of equal treatment for customers receiving equal service.* (281 F. 2d 46) [Emphasis supplied.]

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[21] *In the Matter of Trunkline Gas Company*, Op. No. 321 (1959), 21 FPC 704.

The Court then concluded:

> In this case the examiner and the Commission, with one Commissioner dissenting, reached the conclusion that the costs of the expansion program representing the purchase of new gas and the improvement of the line up to Tuscola, Illinois, should be rolled in as a systemic cost while the costs of the pipeline from Tuscola to Consumer's facilities on the Michigan-Indiana border should be charged solely to Consumers as an incremental cost.
>
> The Commissioner's decision was based on what we believe to be the proper conclusion that the expanded facilities will form part of an integrated Trunkline system and that the expansion will benefit the entire system.
>
> * * * * * * *
>
> We find that the Commission's basic conclusion that this partial expansion would be part of the integrated gas system was proper, and therefore affirm the use of the rolled-in allocation method. (281 F. 2d 47)

Columbia contends that the determination by the Commission in the above case that costs of the pipeline from Tuscola to the Michigan-Indiana border should be treated as incremental costs, charged directly and solely to Consumers, constitutes support for adoption of the zone-gate method in the instant proceeding. In this connection, Columbia emphasizes the following statement by the Commission in its *Trunkline* decision, *supra:*

> The direct assignment of costs beyond Tuscola reflects the greater distance over which this gas must be transported, and in effect results in the creation of a new zone for Trunkline's sales. (21 FPC 704, 711–12)

This contention is wholly without merit. The controlling fact to be borne in mind here is that the Commission's *Trunkline* decision expressed disapproval of the incremental, segregated facilities approach in clear and strong language, as follows:

> The Commission has consistently rejected allocation methods which would, in effect, assign costs of particular main line facilities to a specific customer.
>
> * * * * * * *
>
> Of the three methods of allocating costs on a rolled-in basis presented by Staff in this proceeding, Staff's recommended Method No. 1 is most appropriate in the circumstances of this case. This method of allocation is consistent with our long-standing policy of utilizing a system-wide approach in costing and pricing firm service for gas delivered and sold from a company's main line facilities, and will best serve the public interest by providing for a fair distribution of costs, commensurate with the benefits to be enjoyed by all of the customers of the Panhandle-Trunkline system. (21 FPC 712–13)

The language relied on by Columbia, *supra*, referred to the Commission's determination that the costs of the pipeline from Tuscola to Consumer's facilities on the Michigan-Indiana border should be given a special incremental treatment, based upon the fact that the admitted purpose of this particular line was to deliver and sell 135,000 Mcf per day of increased gas supply *to one customer*, Consumers Power Company. The rationale for the adoption of an incremental approach as to this particular line was spelled out in the Court of Appeals decision, *supra*, affirming the Commission's action as follows:

> Whatever its virtues, use of a "rolled-in" approach alone is not adequate in all situations, *particularly where some assets are used by the utility solely for the benefit of one customer.* At some point in every gas distribution facility the general system ends and connective links to the local distributors' own equipment begins. At this point the facility becomes so identified with its function as a part of the local distributor's gas plant that it may be unfair to charge its costs to all of the customers of the utility. (281 F. 2d 46–47) [Emphasis supplied.]

No such situation, of course, is involved in the instant Tennessee proceeding.

This Commission, going back to the *Canadian River* case, 3 FPC 32, 61–2 (affirmed by the Supreme Court in *Colorado Interstate Gas Company* v. *F.P.C.*, 324 U.S. 581, 588–90), has consistently refused to adopt a segregated facilities, incremental approach for the purpose of allocating costs of an integrated system, and has been upheld in this by the courts. The zone-gate method, as advocated by Columbia and Consolidated in the instant proceeding, is plainly a segregated facilities, incremental approach, predicated on the premise that the customers of a given zone have a vested interest in certain specific portions of the pipeline—and as such it is plainly objectionable.

As a matter of fact the zone-gate allocation method, together with its basic rationale that the facilities in donwstream zones do not benefit or serve the upstream zones and that accordingly no portion of their cost should be charged to the upstream zones, has already been specifically rejected by the Commission in the landmark *Northern Natural* zoning case, Op. No. 281, *supra*. In that case the major controversy was between Northern Natural and one intervenor group, on the one hand (designated the Opponents), who opposed the establishment of zones and zone differentials on the Northern Natural system, and another intervenor group (designated the Proponents) who together with the Commission Staff urged the establishment of zones. Among the proponents of zoning there was a conflict with respect to the specific zoning methods recommended—with the intervenor proponents advocating the adoption of a zone-by-zone allocation method, whereas the staff proposed the Mcf-mile method. The proponents' zone-by-zone method, which involved the establishment of only two zones on the Northern Natural system, was described by the Commission as follows:

> * * * all costs except transmission costs were allocated on a system-wide basis * * * Costs associated with the operation of the transmission main line facilities in Proponents proposed Zone 1 were likewise allocated by them to all customers, excepting those in the Argus System, on a system-wide basis, *on the theory that these facilities are used for serving all customers.* Costs associated with the branch or lateral lines located in that Zone 1 were assigned solely to the Zone 1 customers. Similarly, all costs associated with transmission plant located in their proposed Zone 2 were assigned by the Proponents solely to that zone, *as they are not considered to be used in any way to provide service to Zone 1.* (14 FPC 28) [Emphasis supplied.]

It is important to note here that Proponents' zone-by-zone method in the *Northern Natural* case thus followed the same rationale as the zone-gate method presented by Columbia and Consolidated in the instant proceeding—*i.e.*, that costs of transmission facilities in upstream zones should be distributed between that zone and all downstream zones, whereas costs of transmission facilities in the terminal downstream zone (Zone 2 under Proponents' plan in the *Northern Natural* case, and the New England Zone in the instant Tennessee case)

should be assigned exclusively to that zone. The Commission rejected this zone-gate approach in the *Northern Natural* case with the following language:

> We do not believe it either sound or reasonable to allocate costs in part on a system-wide basis and in part on the basis of a segregation of certain properties as the Proponents have done. (14 FPC 29)

In addition, the Commission there listed as one of the infirmities of the Proponents' zone-gate method the fact that

> * * * under this plan, Zone 1 sales would assume a relatively small and disproportionate portion of the costs associated with the hundreds of miles of lateral lines on the system. (14 FPC 26)

Thus, although the Proponents' plan there assigned all costs associated with the Zone 1 laterals exclusively to Zone 1 customers, the Commission stressed as a point of criticism the fact that the costs of these laterals alone actually represented a relatively small and disproportionate portion of the costs associated with the hundreds of miles of lateral lines on the entire Northern Natural system, and seemed to feel instead that Zone 1 should bear a fair share of the cost of *all* laterals on the system. The same rationale would appear to indicate even more strongly in the instant Tennessee proceeding that the upstream zones should not be freed completely from bearing any share of the cost of the New England terminal zone facilities.

As already noted previously in this decision, the difficulty with the rationale of the zone-gate method is that it ignores the basic character of the Tennessee system as a single integrated system, in which every portion of the system contributes in one way or another to the effectiveness of the entire system, whether directly or by displacement. The fact that Tennessee operates an integrated pipeline system is beyond dispute, and is conceded by all parties to this proceeding. Tennessee sales and deliveries are distributed all along some 1,650 miles of line out of a system length (measured from the weighted average center of gas supply to the northern terminus near Boston) of approximately 1,940 miles. Gas reaching the northernmost terminus of the system is the same gas which flowed through the southern portion of the system. The location of storage facilities approximately 1,500 miles from the sources of system gas supply determined and had a substantial effect upon the amount of capacity built into the system south of storage, as well as the manner in which such capacity is operated. Moreover, the pipeline facilities have been designed and constructed on a basis which would insure the greatest degree of flexibility and reliability in supplying service to all customers on the system, regardless of their location, and the Tennessee lines are interconnected extensively for that purpose. As will shortly be noted in detail the storage facilities benefit not only those customers in the zones downstream therefrom, but also the upstream zone customers. The fact is that the Tennessee system is not truly susceptible to segregation and division in such a way that one zone on the system would not be dependent upon, or affected by another zone. The cost for service rendered in the first rate zone is affected by each change in the load characteristics in the last rate zone. Similarly, changes in load characteristics in the first rate zone affect the cost of service to each and every other zone on the Tennessee system. This mutual dependability is characteristic of an integrated system such as Tennessee. (68:8928–29)

The failure of the zone-gate method to recognize this basic characteristic of Tennessee's integrated system is sharply illustrated by its treatment of the transmission costs related to underground storage. Columbia and Consolidated agree that Tennessee's storage facilities benefit *all* zones either directly or by displacement. As stated by Columbia witness Nissel:

> The underground storage fulfills functionally the role of providing capacity in addition to the flow capacity of the system as and when the demand on the system exceeds the flow capacity of your system. Direct or by displacement, underground storage is useful to customers of any zone on the system. (52:6030)

And the Columbia initial brief states:

> There is no disagreement among the parties to this proceeding that underground storage is used to increase Tennessee's total system capacity and benefits all customers. (p. 31)

Nevertheless, although under the zone-gate method the cost of service associated with *storage facilities*, as such, is treated on a system-wide rolled-in basis, that method does not allocate on a system-wide basis the cost of service related to that portion of the *transmission facilities* which is required in connection with storage operations. (57:7500; 68:8929–30) Admittedly, the presence of storage facilities on the Tennessee system reduces the requirements for main line capacity between supply and storage, from system peak-day to average-day requirements. (21:2873–81) Accordingly, it is clear that if there were no storage, additional pipe and facilities would be required in the Southern Zone, for example, in order to make it possible to handle system peak rather than average day requirements—thus increasing the costs allocable to the Southern Zone. However, although the availability of storage thus reduces mainline costs and thereby benefits the upstream zones, the zone-gate method fails to allocate to the upstream zones any of the direct and indirect costs of downstream facilities which are used to carry the gas into storage—such as the cost of fuel used in downstream zones to carry gas to the storage fields, compressor station maintenance, depreciation on the facilities, return, etc. (52:6038; 57:7500; 68:8929–30) To this extent, therefore, the upstream zones under the zone-gate method receive a service from such transmission facilities for which they are required to make no contribution to cost.

Since underground storage became available in 1955, it has no longer been necessary for Tennessee to provide pipeline capacity equal to the total peak-day requirements of its customers. Instead, the pipeline capacity required *from the source of gas supply to storage*, and the facilities designed therefor, are limited to the annual average daily requirements of the General Service customers, inasmuch as the storage fields provide, either directly or by displacement, the daily requirements in excess of their annual average day needs. The Tennessee system is designed, however, to provide full contract demand volumes for its Contract Demand customers from source of gas supply to point of delivery. (67:8813–14) It is important to observe, in this connection, that the New England Zone consists entirely of General Service customers. Under the zone-gate allocation method, the demand costs of the facilities physically located in an upstream zone (such as the Southern Zone) are distributed between that zone and all downstream zones, including the New England Zone, on the basis of the relative ratios of peak-day use made by each zone. Thus, the New England Zone is charged with demand costs based on maximum-day usage, and no credit is given to that zone to reflect the fact that capacity equal only to its average daily requirements has been constructed from source of supply to storage. The result is that a zone such as New England which consists entirely of General Service customers, is allocated a greater share of demand costs than appears to be appropriate if facilities are to be segregated for allocation purposes, as the zone-gate method purports to do. It is, of course, true that billing demands or average peak-day demands are also used

under the Mcf-mile method to allocate demand costs between zones, and to this extent a similar situation pertains to a limited degree under that method as well. However, since the Mcf-mile method utilizes system *average* costs, this has the effect of rolling in or offsetting individual advantages and disadvantages, thereby minimizing the effect of any such situation under the Mcf-mile method. The situation cannot be viewed so charitably, however, with respect to the zone-gate method, since the entire rationale and justification for that method is that it purportedly determines and assigns "*actual* costs" to each zone by the segregation of facilities.

Another illustration of the failure of the zone-gate method to recognize and reflect the mutual dependence between zones is found in the situation involving the use of transmission facilities in the New England Zone to deliver gas into the New York Zone in order to maximize injections of gas into underground storage. Since the zone-gate method assigns the entire cost of service related to New England facilities against the New England customers alone, none of the upstream zones are charged for any part of the New England facilities which are thus actually used indirectly for storage injection. Tennessee witness Rogers [32] testified that in 1955 the New England facilities were used for delivering gas into the New York area a total of 45 days from November 3 to December 17, 1955. In 1956, gas was moved into the New York City area through New England facilities on five days during the month of November.[33] In 1957, New England facilities were used to deliver gas into the New York area on 74 days during the period from May 23, 1957 through October 24, 1957. In 1958, gas was delivered into the New York City area from New England on 90 days during the period from April 19, 1958 through October 23, 1958. Through the end of August, 1959, New England facilities were used to move gas into the New York City area on approximately 78 days, and deliveries were also made in this manner in September, 1959. From 1956 through 1959, making deliveries to the New York City area in this manner permitted the maximum use of the line from Station 219 to the Hebron storage field for the purpose of storage injections. The availability of the two lines into New England thus provides more flexibility in operations and better utilization of storage than would otherwise be the case, as well as providing an alternate route to the New York Zone in case of emergency. (67:8804)

Columbia contends that this evidence as to the use of the New England facilities to move gas into the New York area, presented as part of the Tennessee rebuttal case, represented "an afterthought designed solely to attack the zone-by-zone approach". However, the evidence is clear that the facilities were actually designed with such purpose in mind, and that Tennessee publicized its intent to operate the facilities in that manner as far back as 1954. (Exh. 135; 67:8825–9) In addition, practically all of Tennessee's compressor stations on the Tennessee system can pump gas either north or south. (67:8872–3)

Columbia directed a great deal of attention, in its cross-examination of witness Rogers and in its initial brief (pp. 30–31), to an effort to raise doubts as to the significance of any use of New England facilities for this purpose. It contends that any such use, if any, was *de minimis* and that facilities in the New England Zone in fact do not serve any other zone. In making this point, Columbia suggests that witness Rogers' rebuttal testimony on this subject was actually in

[32] Tennessee Director of Planning, whose duties consist chiefly of supervising and directing the planning and developing of new projects and pipe line expansion programs, including the preparation and presentation of engineering design data for FPC applications.

[33] Rogers explained this minimum usage in 1956 as follows: "The main reason for this minimum usage was that we did not have much gas available for injection into storage in 1956, due to the high load factor operation of our customers." (67:8805)

conflict with his earlier testimony in this proceeding. It is true that during the course of a brief cross-examination on this subject during the Tennessee case-in-chief at a hearing session in September, 1957, Rogers was asked whether *during the test period 1956* any gas actually passed through the northern line down through New England into the New York area, and he replied, "In the calendar year, I don't believe that any did." (21:2888) At the same time, however he also testified that

> * * * we have at times passed gas into New York City area, for instance, through the northern loop * * * by northern loop, I mean through the line that extends from Mercer north to Buffalo and then on into Massachusetts. We have made deliveries into the New York City area through that line and further reduced the amount of gas going into the Hebron to Greenwich line.
>
> * * * * * * *
>
> As I mentioned, we at times have transported gas into the New York City area through the use of that line * * *. (21:2887)

During his rebuttal presentation at a hearing session in December, 1959 Rogers described in detail the full use made of New England facilities to maximize injections of gas into underground storage, as outlined above—including the moving of gas into the New York City area through New England facilities on five days during the month of November, 1956. When asked to reconcile this with his earlier testimony in 1957 that he did not believe that any gas had moved from New England into the New York area during the calendar year 1956, Rogers replied:

> Mr. Jones, I see the records of the operations of the entire system and unless for some particular reason certain figures are brought to my attention, they are just a mass of figures. I at this time did not recall this particular operation. After all, there were only five days in which we did transport gas to New York City. (67:8851)

This explanation appears to be entirely reasonable, and the point does not merit further attention.

The Columbia brief also suggests that witness Rogers' rebuttal testimony was in conflict with prior representations on this subject allegedly made by Tennessee personnel to Consolidated witness Learned, during the course of an inspection trip over the Tennessee system in the early part of October, 1957. This contention rests upon a statement made by Consolidated witness Learned during the course of his direct testimony, to the effect that his investigations had disclosed only one instance where gas was delivered backward from the New England to the New York Zone, and that this instance had occurred prior to the test year 1956. (47:4957) During subsequent cross-examination, it developed that Learned's conclusion was based upon a single conversation with Tennessee's chief dispatcher in the early part of October 1957; that in the course of this conversation Learned had inquired solely about the instance prior to 1956 "because we knew of that, but we didn't know of any other" (56:7464). Although Learned further testified that the chief dispatcher "indicated that there had been but one instance up to that time", he was not precise as to what period that alleged single instance covered, stating: "It was prior, I think, to the test year 1956, that is the way I understood it." When asked whether he had inquired about any such use of the line *subsequent* to 1956, Learned replied:

> A. He didn't indicate when we were there that there had been any operations of that character in 1957.

Q. Did you ask about it?
A. I didn't ask specifically * * *. (56:7465–66)

It is of interest to note that Learned thus made no specific inquiry as to such use of the line in the year 1957, and under all the circumstances it seems quite likely that the Tennessee dispatcher at the time of this visit understood Learned as being interested only in the test year 1956.

During a lengthly cross-examination of Tennessee witness Rogers, directed exclusively to his testimony with regard to the *November, 1956* movement of gas from New England into the New York area, and in an argument developed in its initial brief on the basis of that interrogation, Columbia attempted to raise a number of suggested *possibilities* of error which conceivably *might* have occurred in the measurements made on the Tennessee system from time to time in the normal course of its operations during 1956—these measurements being the basis for Rogers' conclusion that gas moved into the New York City area through New England facilities on five days during the month of *November, 1956*, averaging 5,000 Mcf per day. (67:8839–49; initial brief, pp. 30–31) No showing was made, however, that any such errors *did* occur. Furthermore, if we are to speculate that errors *may* have occurred from time to time in a given direction, it is equally reasonable to speculate that errors may similarly have occurred in an opposite direction, providing a counter-balancing effect.

In this connection, Columbia states that Rogers agreed

> * * * that there could have been an error of one per cent in the pressure computation; (T. 8845) and that all things considered gas may have actually flowed from New York into Connecticut on the days in question instead of vice versa as he had testified. (T. 8846)

However, an examination of this testimony makes it clear that Rogers stressed that such an error could only have produced a result of this character in the case of the "very small delivery volume days" which occurred in November, 1956, averaging only 5,000 Mcf per day. He stated:

> * * * I don't believe that there would be enough pressure change to bring about that situation in a day, such as August of 1958, where we had 60,000 passing into New York. (67:8846)

This, of course, represents a most important qualification since the volumes involved were much higher than 5,000 Mcf per day in the years 1955, 1957, 1958 and 1959.

Columbia further contends that Rogers testified that if per chance gas did move from Connecticut to New York in the manner alleged it may have resulted not from any plan to so move the gas but rather from Tennessee's decision to maintain a certain pressure at some location in New York or Pennsylvania for an entirely different purpose. However, an examination of the record (67:8857–59) makes it perfectly clear that Rogers expressed his agreement with this *possibility* only in connection with the very small volume movements of this character which took place during the year 1956. He made no such statement with respect to the large-volume movements which occurred in the later years.

It is to be noted that throughout this entire discussion Columbia limits its attention exclusively to the matter of the movement of gas through the New England facilities into the New York area during the test year 1956. However, this narrow and artificial approach is not helpful or realistic in the light of the problem to be resolved here—the determination of a fair and reasonable method of allocation to be applied to the Tennessee system for the future. That decision should not be based upon a narrow consideration of the extent to which the

New England facilities were used in a manner beneficial to the upstream zones in the test year 1956 alone, but should involve a broad consideration of the entire characteristics and potentialities of the New England operation as a part of Tennessee's integrated system. When viewed in that light, the use made of the New England facilities in more recent years becomes material and significant.

Columbia finally contends that even if the New England facilities were truly used for the purpose of transporting gas into the New York Zone in the manner described by witness Rogers, any such use would have been in violation of the limited terms of the authorization granted by the Commission to Tennessee's wholly-owned subsidiary, Northeastern, authorizing its original construction of a pipeline system in New England and its sale of gas to specified retail companies in New England for resale; that any such use of the New England facilities as described by Rogers would therefore have constituted an unlawful operation, and costs should not be allocated in this proceeding on the basis of an unlawful operation. This Columbia argument is bottomed exclusively upon the fact that in an order issued on March 21, 1951 in Docket No. G–1267 (Op. No. 210, 10 FPC 135), wherein the Commission authorized Northeastern "to substitute 144 miles of 24-inch pipe for the same length of 20-inch now authorized, and to substitute larger sizes of pipe in five of the authorized lateral lines", the following condition was included:

> (a) The facilities authorized herein shall be used only as proposed by applicant, namely: (i) to provide natural gas service to the customers Northeastern is presently authorized to serve by opinion 9 FPC 271 and accompanying order issued November 8, 1950; (ii) to meet emergency demands which may arise by reason of emergency interchange of natural gas between Northeastern and any other natural gas transmission company or companies in New England; and (iii) to provide natural gas service in the state of Massachusetts north of Northeastern's presently authorized facilities, and in the states of Maine, New Hampshire, and Vermont, in which areas Northeastern has stated herein that it intends to provide such service; and, for such purposes, only as authorized by order of this Commission.

An examination of Opinion No. 210 itself reveals that the quoted condition there imposed upon Northeastern had no conceivable connection with the problem involved in the instant proceeding, and that the Columbia argument is not entitled to serious consideration. The quoted conditions, of course, had its origin in the fact that originally Northeastern had been locked in a competitive struggle with another pipeline company, Algonquin Gas Transmission Co. (Algonquin), for authorization to serve the New England area. This problem had been resolved by the Commission in its Opinion No. 202 issued November 4, 1950 (Docket No. G–124S, *et al.*, 9 FPC 271), by authorizing Northeastern to serve certain specified companies in the New England area and authorizing Algonquin to serve the remaining New England companies. Subsequently in Docket No. G–1267 Northeastern had applied for authority to substitute 144 miles of 24-inch pipe for the same length of 20-inch pipe already authorized, and to substitute larger sizes of pipe in five of the authorized lateral lines. Algonquin intervened and filed a motion to dismiss. In its Opinion No. 210 granting the requested authority to Northeastern, the Commission stated that the previous grant of limited certificates to both Northeastern and Algonquin had

> * * * removed any competition which might otherwise have existed between Algonquin and Northeastern, unless the additional capacity to be made available through the substitution now proposed by Northeastern

might be used by it as a basis for future requests for authorization to serve markets Algonquin is now authorized to serve.

However, Northeastern * * * had made it clear on this record that this additional capacity is intended for other purposes. Further, conditions attached to our certificate issued herein limit the use to which the additional capacity may be put * * *. (10 FPC 142)

* * * * * * *

Nor do we by our action here authorize Northeastern to construct pipeline capacity for the purpose of service by it to those markets which have been denied to it by our opinion 9 FPC 271 and accompanying order issued November 8, 1950, and by our opinion 10 FPC 35 and accompanying order issued February 27, 1951, wherein a certificate of public convenience and necessity was granted to Algonquin. (10 FPC 140)

* * * * * * *

Under the circumstances disclosed by the record before us, it is just and reasonable and the public interest requires that any additional capacity which may be available on the Northeastern system, as presently authorized, through the substitution of larger sizes of pipe as proposed, shall be used only for the purposes which Northeastern states it intends to use such additional capacity. (10 FPC 141)

The above language makes it crystal clear that the quoted condition laid down by the Commission to Northeastern in Opinion No. 210 was intended only to insure that Northeastern would not encroach upon New England territory which had been certificated to Algonquin and denied to Northeastern in the earlier competitive proceeding. It obviously has no conceivable connection with the matter of Tennessee's current use of its own New England facilities to move gas into the New York area.

The common sense of the situation is that since the Commission's merger order of July 16, 1954, authorizing Tennessee to acquire and operate the certificated system of Northeastern, the latter company's facilities and operations were merged into and became an integral part of Tennessee's integrated system, and became available for use as any other facilities on that entire system—*i.e.*, in any way necessary or desirable for service to all customers on the entire Tennessee system, as expanded by the merger, and throughout all areas which both Tennessee and Northeastern were previously authorized to serve.

Another major defect in the zone-gate method lies in its accentuation of the impact upon cost allocation resulting merely from the historical location of geographical zone boundaries on the Tennessee system. It is to be noted at the outset, in this connection, that none of the parties have proposed any general re-examination in this proceeding of the existing zone boundaries on the Tennessee system, for the purpose of determining whether they are proper and appropriate, or whether they should be changed.[24] Accordingly, the only issue being here determined is the method to be adopted for the allocation of total system costs among the *existing* zones on the Tennessee system. Nevertheless, the problem of the location of the zone boundaries *is* inherently involved in the matter of zone allocation, in a manner which will presently be developed.

It is important to recognize that the zone lines on the Tennessee system were established historically as a matter of convenience in administering rates, rather than with a view to cost allocation. They were admittedly not scientifically

[24] Intervenor Iroquois Gas Corporation complains of the existing zone boundary between the Northern and New York Zones, but presented no proposal for a general re-examination of existing zone boundaries. The Iroquois contention will be discussed at a later point.

established as proper zones for the purposes of allocating costs on a zone-gate basis. As earlier noted, the underlying philosophy of the zone-gate method is to treat each different zone as if it were a separate corporate entity, with the customers in each zone being treated as if they were customers of separate operating companies. There is no reason to assume, however, that if service to the various customer areas on the Tennessee system had in fact been developed originally on the basis of separate corporate entities, they would have been organized on the basis of such geographical boundaries as those reflected by the current zones on the Tennessee system. Nor is there any reason to assume that the Commission, if it had in fact decided to adopt the zone-gate method when the Tennessee system was first zoned, would have found the existing zone boundaries suited to and appropriate for use in connection with that particular allocation method.

The importance of this problem may be indicated by referring to the Eastern Zone. By mere fortuity the Eastern Zone, in the historical development of the zones, became the smallest zone on the Tennessee system, with a relatively small amount of plant and facilities located therein, but with large volumes of gas sales. By contrast, the Northern Zone became a larger zone, containing a considerably larger amount of plant. Thus, there is only one compressor station in the Eastern Zone, but five in the Northern Zone. As of the end of 1956, there were 1,165 miles of pipe in the Northern Zone, but only 176 miles of pipe in the Eastern Zone. Under any cost allocation method, this difference in zone sizes gives the Eastern Zone, where Columbia and Consolidated make most of their purchases from Tennessee, a distinct benefit or advantage. Under the zone-gate method, however, this advantage is aggravated. Under that method, a customer located at the beginning of a large zone is charged with a proportionate part of the cost of service associated with *all* the facilities located in that zone, even though, as is the case in the Northern Zone, some of those facilities are located some 500 miles beyond the point of delivery of gas to the first customer in the zone. On the other hand, a customer located at the beginning of a small zone is charged with a proportionate part of a much smaller cost of service. (56 : 7443–4)

It is, of course, true that the costs allocated to the various customer companies will similarly vary, to some extent, depending upon where the zone boundaries are located, even under the Mcf-mile allocation method. However, the ultimate impact of the geographic location of the zone boundaries is far less significant under the Mcf-mile method, where the use of system-wide average costs itself provides a blending process, averaging out the various advantages and disadvantages which flow from the use of zone boundaries in designing rates. The zone-gate method, on the other hand, *accentuates* the favorable and unfavorable situations. It is concluded that any decision in the instant proceeding will be more soundly based and will have more lasting value, to the extent that it tends to *diminish* rather than to accentuate the importance of the geographical zone boundaries. Although the Mcf-mile method cannot entirely eliminate this inherent zone boundary problem, it can and does reduce the resulting inequities to a minimum by assuring as equitable and uniform treatment as possible to all customers, regardless of their geographical location.

Another inherent weakness in the zone-gate allocation method lies in its complexity and in the great possibility for hidden error which is inherent therein. That the method is in fact unusually complex is evident from an examination of the extensive exhibits employed in its presentation. This was further demonstrated by the great time and effort required to correct a single error in Consolidated's Exh. No. 78, which was disclosed in the course of cross-examination of Consolidated witness Chaney. Chaney there concluded that he

had erred in assigning Compressor Stations 87 and 114 to the Southern Zone and the Central Zone, respectively. His further investigation and consideration of this problem, and the subsequent correction of the exhibit to reflect the shifting of Station 87 to the Central Zone and Station 114 to the Eastern Zone, became a major enterprise which is illustrative of the inherent complexity of the zone-gate method. (57:7495, 7498; 59:7726; 62:8059; Supp. No. 5 to Exh. 117).

In addition, the fact is that much of the basic data required under the zone-gate method in order to establish the costs alleged to be incurred within each zone had to be developed from innumerable preliminary allocations, and these allocations themselves were necessarily based on judgment factors. (Exh. 78 and 79; 58:7594–7613) By contrast, the Mcf mile method, as adopted and approved by the Commission in the *Northern Natural* case, Op. No. 281, *supra*, is basically simple, and is applied directly to the system-wide cost of service, without the necessity for numerous preliminary allocations. It entails a minimum of effort, and its results can readily be checked for accuracy.

The Courts have generally supported the Commission's efforts to develop methods and techniques which do not unnecessarily impose onerous administrative burdens, and which are practical or feasible from the management and regulatory point of view. For example, in the Court of Appeals decision affirming Op. No. 281, *Interstate Power Company et al.*, v. *Federal Power Commission*, *supra*, the Court quoted the Commission's statement that:

> In theory, the ideal non-discriminatory and non-preferential rate structure would be one designed to assess each point of sale and delivery with the total of the various cost components incurred in the rendering of service to each point. But any attempt to arrive at such perfection would not only be delusory * * * but also impracticable and infeasible from both the management and regulatory point of view. In the circumstances of this case the only practical and reasonable approach to an equitable solution is the establishment of service zones with rate differentials. * * * (236 F. 2d 384)

The Court then stated:

> In effect much of the argument of petitioners here constitutes attack upon this conclusion of the Commission. It is contended that the Commission should have had more data respecting the comparative costs of transmission to all the different areas and points of delivery in the system, *but we think The Commission's declaration as to what was practical or feasible from the management and regulatory point of view is entitled to weight and may not be disregarded.* (236 F. 2d 384, footnote 4) [Emphasis supplied.]

Similarly, in *State Corporation Commission of Kansas* v. *F.P.C.*, 206 F. 2d 690, the Commission had allocated transmission general expenses to demand and commodity on the basis of the same ratios developed from all other supervised expenditures. The petitioner contended, however, that the various items of administrative and general expenses were actually not homogeneous but covered a variety of items, and that accordingly separate consideration should have been given to the various items entering into the whole amount. The Court stated, however:

> It may well be that the Petitioners method would be more accurate, but it is proper for the Commission, which is charged with the administration of the Natural Gas Act, to consider the practical effect of more detailed studies in this regard. (206 F. 2d 711)

Similarly, in the recent Court of Appeals decision in *Battle Creek Gas Company* v. *F.P.C.*, *supra*, the Court in referring to the rolled-in systemic approach as distinguished from the segregated cost approach stated:

> This method has many apparent advantages and the Commission has repeatedly stated a general preference for it wherever it may equitably be used. *It avoids the onerous administrative burden of having to assign a different portion of the cost to each of a large number of customers.* (281 F. 2d 46) [Emphasis supplied.]

It is of interest to note that during the closing stages of the hearing, long after all of the different zoning presentations had been fully presented and cross-examined, and after each of the parties had been provided with an opportunity to distribute further evidence rebutting any of the other zoning proposals, Consolidated made a belated offer of a new and still further allocation method, described as a "pipesize-mile" (or inch-mile) method of allocation (Exh. 118) In essence, this last-minute proposal represented an effort by Consolidated to get around the criticism directed to the complexity of the zone-gate method, and indicated its own qualms as to the complexity and cumbersomeness of that method. The Presiding Examiner's ruling excluding this last-minute effort to introduce a totally new allocation proposal was affirmed on appeal, by the Commission's order of December 10, 1959. It appears that the "pipesize-mile" method, as thus proposed by Consolidated, would have allocated $1,600,000 more to the Eastern Zone than is allocated under Consolidated's zone-gate method—which latter method already allocates $1,300,000 more to that zone than under Columbia's capacity-credit method. It is thus understandable that Columbia has shown no enthusiasm for this last-minute Consolidated proposal.

The Columbia Capacity-Credit Method

We now turn to a detailed discussion of the Columbia zone-gate, capacity-credit allocation method. As earlier noted, Columbia applies the zone-gate method in a peculiarly complicated manner, as a result of its adoption of the "capacity-credit" technique as a substitute for the Commission's *Atlantic Seaboard* method (Op. No. 225, 11 FPC 43), for classifying fixed costs between demand and commodity. Unlike the other parties to this proceeding, Columbia rejects the Commission's long-established Atlantic Seaboard method under which fixed costs are assigned 50% to the capacity (or demand) function and 50% to the volume (or commodity) function. It instead assigns 100% of fixed costs to the capacity function, but then proceeds to use the complicated "capacity-credit" method for the purpose of assigning *some* portion of fixed costs to interruptible deliveries. The Columbia presentation thus weaves the extremely complicated capacity-credit technique into and on top of the already unduly complex basic zone-gate method in a monstrously complicated and involved mathematical exercise. The end result is that substantially more costs are classified to the demand function and less to the commodity function than would be the case under the long-established *Atlantic Seaboard* method—*i.e.*, more than 90% of transmission costs are thus classified in the demand component—thus effecting a material shifting of costs from high load factor customers, such as Columbia, to low load factor customers. Its final effect is to produce an allocation of almost $1,300,000 less cost to the Eastern Zone, where Columbia purchases most of its gas, than under the *Atlantic Seaboard* formula. (Exhs. 109–110.)

The entire rationale for Columbia's use of the capacity-credit method rests upon the proposition, advanced at length in the testimony of its allocation witness Nissel and in its briefs, that the Commission's long-established *Atlantic Seaboard* method is arbitrary and improper and should be discarded—or, in any

event, should not be applied in this case on the ground that the Tennessee system is allegedly characterized by entirely different operating facts than those which were involved in the *Atlantic Seaboard* case. In discarding the *Atlantic Seaboard* method, Columbia's witness Nissel concluded that some other method must be devised to make interruptible sales bear some portion of fixed costs, and he adopted the capacity credit method as the answer to this problem. Nissel described the capacity-credit method as one under which firm customers are charged with the cost responsibility for capacity used by them, as well as for the unused capacity which they create, less a credit amounting to the net charges made to interruptible customers. Interruptible customers, on the other hand, are charged for capacity used by them, less a credit for curtailments which they sustain in vacating capacity for firm customers. (47:5230–1) Interruptible customers are thus required to make *some* contribution to fixed costs.

The Columbia attack on the *Atlantic Seaboard* classification method rests largely upon the following thesis:

> * * * it has adopted a fiction, namely 50 percent of fixed costs will, for the purposes of classification and allocation, be considered as variable costs. By abandoning a factual analysis of cost behavior and substituting an arbitrary fiction contrary to the facts, the Commission has deprived itself of a valid foundation upon which to exercise an informed judgment when making an allocation. (p. 71 of initial brief.)

The suggestion that under the *Atlantic Seaboard* method fixed costs are arbitrarily, and by a fiction, considered and treated as variable costs does not constitute an accurate characterization of the *Atlantic Seaboard* decision, and it introduces a great deal of unnecessary confusion. The fact is that in the *Atlantic Seaboard* case the Commission continued to characterize fixed expenses as such, and made no effort whatsoever to describe them as anything else. However, the Commission concluded that 50 percent of such fixed expenses (or capacity-costs) should fairly and properly be allocated to and borne by the commodity (or volume) function, as distinguished from the capacity or demand function. This conclusion was reached, after careful analysis, on the ground that the capital outlay for pipeline facilities is made and justified not only for service on the peak days but for service throughout the year; that accordingly both capacity and volume are to be regarded as cost factors or "incidences" in respect to the capital outlay for a pipeline project. The issue to which the Commission addressed itself in the *Atlantic Seaboard* case was not whether admittedly fixed costs should be considered as variable costs, but rather whether the admitted fixed charges *must* be charged 100 percent to the demand or capacity function, with the volume function not being required to bear any portion of any such fixed costs. The Commission stated:

> In this present case, applicants, generally speaking, allocated fixed costs or expenses, except return on investment and related income taxes, to the capacity, or demand function. * * * The staff, on the other hand, apportioned all fixed costs or expenses equally between demand and volume. * * *
>
> * * * * * * *
>
> Both capacity and annual use are important considerations in the conception of the project and in the issuance of certificates of public convenience and necessity. Both capacity and volume, therefore, are what are known as cost factors or incidences in respect to the capital outlay for a pipeline project. It follows that reasonably accurate results can be achieved only by allocating the fixed expenses flowing from the capital outlay to both operating functions, viz, capacity and volume. (11 FPC 54)

* * * * * * *

> To reiterate—and emphasize—fixed costs or expenses are incurred for both peak use and annual use in respect to both demand and volumetric functions. They are important cost factors in respect to both services. To achieve a reasonable equitable result—they must be apportioned to both services. (11 FPC 55).

The second major argument made by Columbia is that the *Atlantic Seaboard* method should not be applied in the instant case in any event, on the ground that the Tennessee system is allegedly characterized by entirely different operating facts than those which were involved in the *Atlantic Seaboard* case. In this connection, Columbia contends that the Commission adopted the *Atlantic Seaboard* method because it had concluded that its previous method of allocating demand costs "achieved an inequitable result because it did not charge any fixed or capacity-cost *to interruptible customers cut off on the peak day*" (initial brief, p. 70); that the controlling consideration which led the Commission to adopt the *Atlantic Seaboard* method was its desire to classify costs in such a way as to assign some portion of capacity-costs to interruptible business; that the percentage of interruptible sales on the Tennessee system, however, is very low, amounting to only 4.3 percent of total sales in the test year, and that the Tennessee system accordingly does not involve in any significant way the basic problem which the *Atlantic Seaboard* method was designed to handle. (Reply brief, p. 43.)

Here again, Columbia has misread the intent and significance of the Commission's *Atlantic Seaboard* decision. The fact is that the Commission was not there concerned merely with the narrow problem as to how a fair share of fixed costs could be charged "to *interruptible* customers cut off on the peak day." Rather, the Commission was concerned with the much broader problem as to how fixed or capacity-costs could be apportioned *to both peak use and annual use.* The Commission stated:

> A pipeline would not normally be built to supply peak service, that is to say, service on the peak days only. We know from our administration of section 7 of the Natural Gas Act, which involves the issuance of certificates of public convenience and necessity, that pipelines are built to supply service not only on the few peak days but on all days throughout the year. In proving the economic feasibility of the project in certificate proceedings, reliance is placed upon the annual as well as the peak deliveries. Stated another way, the capital outlay for the pipeline facility is made—and justified—not only for service on the peak days but for service throughout the year. Both capacity and annual use are important considerations in the conception of the project and in the issuance of certificates of public convenience and necessity. Both capacity and volume, therefore, are what are known as cost factors or incidences in respect to the capital outlay for a pipeline project. It follows that reasonably accurate results can be achieved only by allocating the fixed expenses flowing from the capital outlay to both operating functions, viz, capacity and volume. (11 FPC 54).

It is thus important to bear in mind here that the purpose of the *Atlantic Seaboard* method was to achieve a proper allocation of fixed costs *to all off-peak service*, and not merely to interruptible service. It is clear that the Commission's reference in the *Atlantic Seaboard* decision to interruptible service, which is so emphasized here by Columbia, was made only by way of illustration. After discussing the broader problem in the language quoted above, the Commission there stated:

> The soundness of the foregoing conclusion will be made clear by a *simple illustration.* If fixed expenses are assigned wholly to the demand or capacity function, then gas service which is interrupted on peak days will not share in any of the fixed costs. (11 FPC 55). [Emphasis supplied.]

The point made above is a most important one to bear in mind in connection with the Tennessee system. Here, although interruptible sales represented only 4.3 percent of total sales in the test year, there are firm customers such as Columbia in the Eastern Zone, whose takes are not interruptible and cannot be curtailed during the peak period, but who nevertheless take very large volumes of *off-peak* gas. As pointed out above, the controlling objective of the *Atlantic Seaboard* decision was to compel such large volume users to bear some portion of fixed costs related to their *annual use.* It accordingly is clear that the fact that Tennessee has only a small percentage of interruptible sales is totally irrelevant here.

As a matter of fact, Columbia itself in the very course of its argument on this subject observes in a footnote that "as a matter of fact the Seaboard System had no interruptible customers." (Reply brief, p. 43). Under these circumstances, it is difficult to see how it can seriously be contended that the Commission in adopting the *Atlantic Seaboard* method was directing itself merely to the narrow "interruptible service" problem.

In connection with its contention that the Tennessee system is characterized by entirely different operating facts than those which were involved in the *Atlantic Seaboard* case, Columbia emphasizes that the Tennessee system provides a wide variety of types of service (a factor allegedly not present in the Seaboard case), and that the Tennessee system is marked by wide variations in load factor between zones. Columbia stresses, in this connection, that Tennessee provides firm but very low load factor services to certain customers (particularly the New England Zone), thereby requiring substantial capacity which was used solely to meet winter peak requirements; that if the *Atlantic Seaboard* method is employed here, such low load factor customers will not be charged with an adequate portion of capacity costs connected with rendering such service, and thus a substantial part of such capacity costs incurred for the low load factor customers would be shifted to and paid by high load factor customers, such as Columbia. In this connection, Columbia states:

> * * * the high-load-factor Columbia Companies have invested approximately 118 million dollars in underground storage facilities to enable them to maintain high load factor purchases of southwest gas to meet low load factor market requirements. * * * Columbia Companies and their wholesale customers also have invested many millions of dollars in peak shaving facilities for the same purpose. The Atlantic Seaboard formula would shift the benefits of these enormous investments, and the related costs of many millions of dollars per year to other customers of Tennessee, who do not share in the costs which make these high load factors possible. (Initial brief, p. 78).

The fact is, however, that these identical objections were fully considered and rejected by the Commission in the *Atlantic Seaboard* case, and in the relatively recent *El Paso* case (Op. No. 326, August 1959, 22 FPC 260). The argument here made by Columbia was answered by the Commission in clear and unequivocal language in its *Atlantic Seaboard* decision, as follows:

> It is our opinion that these significant cost factors should be weighted equally, that is to say, 50 percent should be assigned to demand and 50 percent to commodity. In this manner all gas transported by the pipeline

will share in all of the various kinds of expenses incurred to transport the gas. Gas which is associated with delivery on the peak day or a group of peak days will share in the total expenses including the total of the fixed charges. That gas which is not associated with deliveries on the peak day or group of peak days will not share in 50 percent of the fixed costs. This solution recognizes the principle that costs associated with peak service are higher than those which are associated with interruptible or off-peak service. In our opinion it reasonably assigns these heavier costs to the service associated with peak deliveries. By the same token, while relieving off-peak service from sharing in 50 percent of the fixed expenses, it, nevertheless, assigns to that service some of all of the costs incurred to construct and operate the pipeline. (11 FPC 56).

In the El Paso case, *In the Matter of El Paso Natural Gas Company*, 22 FPC 260 (Op. No. 326, August 10, 1959), the Commission stated:

> The Southern California Companies and P. G. & E. except to the use of the *Seaboard* formula for the classification of costs in this proceeding and to the assignment of all production costs, including fixed costs, to the commodity component. They argue that the facts of El Paso's and Atlantic Seaboard's operations differ significantly, in that the California market comprises 80.5% of El Paso's sales at almost 100% load factor, whereas Atlantic Seaboard's principal customers all had low load factors and substantial interruptible sales apart from physical differences between the systems. P. G. & E. argues at some length that, because the California customers take at 100% load factor and the other customers take at a much lower load factor, the California customers are paying more than their share of the capacity costs.
>
> In our opinion, the *Seaboard* formula, although not to be followed rigidly in all cases, is a rule of general application, whose virtue is to require that the volume of gas sold will pay part of the capacity costs. *It may be true, as P. G. & E. points out, that a high load factor customer will pay more of the capacity costs than a lower load factor customer of the same demand; but the high load factor customer is obtaining greater service from the pipeline and property can be required to bear a larger proportion of the capacity costs.* (22 FPC 279) [Emphasis supplied.]

The instant Columbia argument was rejected even more strongly, and in greater detail, in the Commission's Opinion and Order Denying Rehearing and Granting Stay in the *El Paso case*, Op. No. 326–A, 22 FPC 659 (Oct. 8, 1959), as follows:

> The Southern California Companies object to the application of the *Seaboard* formula of classification to El Paso. In Opinion No. 326 we have discussed this matter and have concluded that the *Seaboard* formula is a rule of general application by which the volume of gas sold is required to pay part of the capacity costs. The Southern California Companies argue that the high load factor customers, such as the California customers, make greater use of the capacity provided for them and are penalized by requiring them to pay part of the costs incurred for the less efficient users of the capacity. However, this conclusion assumes the invalidity of the *Seaboard* formula. *We think that the heavy users of the facilities should bear a greater share of the capacity costs than the light users.* Of course, the higher the load factor, the lesser the unit cost to the purchaser of gas. The Southern California Companies contend that El Paso's California customers have provided their high load factor through a combination of

sales to interruptible customers and underground storage, and that if costs are improperly placed in the commodity category underground storage development will be discouraged, and it will be increasingly difficult to sell industrial gas. But we are of the opinion that to treat all customers equitably something akin to the *Seaboard* formula is necessary, and to depart from the *Seaboard* formula is to place a greater burden on the domestic and commercial low-load factor customers, who should not have to bear the costs of serving the industrial customers unless absolutely necessary to assure the economic feasibility of the pipeline. (22 FPC 665) [Emphasis supplied.]

We note, in conclusion, that the Commission has consistently followed the *Atlantic Seaboard* classification method since it was first adopted in 1952, and has consistently rejected all attempts to persuade it to depart from that method. In addition, the Commission has been upheld in this position by the courts. For example, in *State Corporation Commission of Kansas* v. *F.P.C.*, 206 F. 2d 690 (1953), the same type of basic attack on the *Atlantic Seaboard* method as that pressed here by Columbia was rejected by the court as follows:

> Basic to Northern's general position is its contention that "once the character of the cost is determined [that is, whether the cost is fixed or variable], the realm of judgment is passed and the demand-commodity formula requires that fixed costs be allocated to demand and volumetric costs be allocated to commodity."
>
> Concededly, the Commission did not so apportion the fixed costs. Instead, for example, the Commission assigned the item of depreciation (a fixed cost) 50% to the demand component and 50% to the commodity component. * * * It refers for such reasons to its opinion in Atlantic Seaboard Corporation, Opinion No. 225 * * *.
>
> * * * * * * *
>
> In general then, Northern's contention that use of the demand-commodity method in the manner it was used herein was erroneous as a matter of law, is rejected.
>
> * * * * * * *
>
> * * * we have rejected Northern's contention that a fixed charge *must* be allocated entirely to demand * * *. (206 F. 2d 709–711)

Where a principle such as the *Atlantic Seaboard* method of cost classification has so long been established and accepted as a traditional part of the Commission's method in pipeline rate proceedings, and where the industry has for so many years been operating on that basis, a heavy burden is imposed upon any party who seeks to have that method rejected at this late date. It is concluded that that burden has not here satisfactorily been met by Columbia. It is of interest to note, in this connection, the view expressed on this subject by Consolidated zone-gate witness Learned, who testified as follows:

> I am in agreement with the *Atlantic Seaboard* principle that requires fixed costs to be split on some basis between the demand and commodity component. And I recognize that the amount of the split, as distinguished from the principle, may be varied in accordance with the facts of a particular case. But I regard the 50–50 split of fixed costs between demand and commodity, which the Commission adopted as a judgment figure in the Atlantic Seaboard case, as a reasonable split here in the absence of the kind of detailed study which would be required to establish a different apportionment of fixed costs as between demand and commodity.

The proposed testimony of Columbia does not contain such a detailed study as would be required to establish a different apportionment of fixed cost as between demand and commodity from the Commission's 50-50 judgment split which it used in the Atlantic Seaboard case, and which I have used in my zone-by-zone cost exhibit. (47:4968-69).

Since it is concluded here that the *Atlantic Seaboard* classification method should not be discarded for the purpose of this proceeding, the entire justification and basis for the application of Columbia's capacity credit method is eliminated. In addition, however, the capacity credit method as here proposed by Columbia contains inherent defects which militate against giving it serious consideration in this proceedng.

As noted above, the capacity credit method as presented by Columbia witness Nissel involves basically two steps: (1) a determination of the capacity to be charged to firm customers, and (2) a determination of the capacity charge to interruptible customers, which in turn is credited to firm customers. The interruptible customers, whose capacity costs were thus determined under this second step, consist of the SO (Sellers Option) customers and the TS (Temporary Service) customers, and these interruptible sales, as already noted, amounted to only 4.3 percent of the total sales of the Tennessee system for the test year. (Tr. 7036).

Nissel's detailed explanation of his capacity credit method appears in his direct testimony at 47:5233-52. In describing how he derived the capacity costs to be charged to interruptible customers (which in turn are then credited to firm customers), Nissell set up an illustrative, hypothetical situation involving an interruptible customer whose annual deliveries amounted to 3,285,000 Mcf, whose daily requirements amount to 15,000 Mcf per day, and who is curtailed 146 days. This customer vacates 9,000 Mcf per day during 146 days for the priority use of firm customers, and he is therefore given a curtailment credit for 146 times 9,000 Mcf per day, or 1,314,000 Mcf. The capacity charge to this interruptible customer is then based not upon the total annual volume of 3,285,000 Mcf actually delivered to him, but rather on such total volume minus the curtailment credit of 1,314,000 Mcf—or 1,971,000 Mcf. The net effect is that this interruptible customer is charged with a capacity cost representing that of a firm customer with 100% load factor, but applied only to 60 percent of the total annual volumes delivered to him (*i.e.*, 100 percent of actual annual deliveries, minus the 40 percent curtailment suffered by him). Another way to state this, while obtaining the same final result, is that this interruptible customer is charged for the entire annual volume of 3,285,000 Mcf actually delivered, but on the basis of only 60 percent of the capacity charge applicable to a firm customer with 100 percent load factor. (53:7063, 7065).

The capacity charge of 1,971,000 Mcf thus derived for the interruptible customer is then credited to firm customers A, B, and C in Nissel's hypothetical illustration in proportion to the "unused capacity" created by each of them. This is on the theory that interruptible deliveries are made possible only to the extent that unused capacity is created by firm customers. (47:5237).

Nissel set forth a numerical example of this hypothetical illustration on Schedule 11, page 21 of Exhibit 85. The maximum demands of the three firm loads A, B, and C, amounting to 20,000, 50,000, and 30,000 Mcf per day, respectively, were there entered in Column (2), Lines 1, 2, and 3 of that Schedule. These three loads were charged for capacity in proportion to their maximum demands, and they were therefore charged with responsibility for "*total available capacity*" during the year amounting to 365 times maximum demand, as entered in Column (3). Used capacity, or actual deliveries, were then entered in Column (4), including a used capacity of 3,285,000 Mcf for the interruptible load.

The *used capacity* of loads B and C were deducted from *total available capacity*, to obtain the "*unused capacity*" figures set forth in Column (5).[35] As noted above, based upon the interruptible customer's curtailment credit of 1,314,000 Mcf, a capacity charge of 1,971,000 Mcf was derived for him, as set forth in Column (7), Line 5. That capacity charge was then entered in Column (6) headed "Capacity Credit," at Line 4—to be used as a credit to the firm loads, and to be shared between loads B and C in proportion to their "*unused capacity*" as shown in Column (5). The capacity charge set forth in Column (7) equals *used capacity* (Column 4), plus *unused capacity* (Column 5), less the applicable *capacity credit* (Column 6). The capacity charges thus derived in Column (7) are then translated into percentages of the total capacity charge of 36,500,000 Mcf (shown in line 6)—and these percentages are entered in Column (8) under the heading "Capacity Responsibilities." The net result, under this illustration, is that load A, representing a 100 percent load factor customer, was charged with the capacity cost for the full 20,000 Mcf per day which it uses on the peak-day and throughout the whole year. Load B, with a peak-day requirement of 50,000 Mcf per day, is charged for only 47,850 Mcf per day, as a result of its capacity credit; and similarly, load C, with a peak-day requirement of 30,000 Mcf, is charged for only 26,750 Mcf per day. The balance of the capacity cost of 5,400 Mcf per day is charged to the interruptible load for the off-peak use of capacity.

The illustrative example as thus presented is not, of itself, impossibly difficult to grasp. However, when this capacity credit technique is woven into and applied as an indivisible part of the already complicated zone-gate procedure, it becomes a monstrously complicated and involved mathematical exercise. Columbia's witness Nissel's attempts to explain it even on direct examination, where he was not subject to interruption, involved a tremendous amount of painstaking effort, requiring lengthy testimony and the use of complicated exhibit tables and charts. The attempts to explore and clarify the workings of the method in the course of cross-examination plunged both the parties and the Presiding Examiner into a seemingly endless and bewildering maze. Even with the benefit of the detailed briefs filed since the conclusion of the hearing the complexities of the method have been such as to require the expenditure of a tremendous amount of time and energy on the part of the Presiding Examiner in order to obtain a clear understanding and a correct picture as to the manner in which the method works. It is concluded that it is not practicable, from an administrative standpoint, to give serious consideration to a method or technique which is so unusually time-consuming and which involves such burdensome complexities.

In addition to its unusual complexity, the Columbia capacity credit method also suffers from certain other inherent defects. Consolidated zone-gate witness Learned succinctly characterized these defects as follows: 1) that the capacity credit method bases an allocation of capacity responsibility upon non-coincidental peak demands;[36] 2) that it makes the assumption that only *interruptible* deliveries use the vacated capacity on a pipeline as indicated by a non-coincidental demand determination. (47 : 4964–70.)

Learned noted, in this connection, that the capacity credit method determines the capacity responsibilities for the firm customers based upon "average billing

[35] Since Load A represented a 100 percent load factor customer, no unused capacity is shown for him.

[36] A coincidental peak demand would represent the total deliveries on the single day when the system made its maximum deliveries for a given period. A non-coincidental peak demand would involve taking the maximum day delivery to each customer during a given *peak period*, and combining them into one aggregate total, even though that aggregate combined total could *not* physically have been delivered by the system on any given day, in view of its total physical capacity.

demands or equivalents;" that the average demands for the Contract Demand (CD), General Service (G), and Transportation (T) customers are the annual billing demands developed by Tennessee's witness Davis, divided by 12, and these annual billing demands are based upon non-coincidental peak-day deliveries; that this method of determining peak-day responsibility based upon "average billing demands or equivalents" can best be classified as an estimated non-coincidental peak-time requirement. He stated:

> I do not consider it proper to base an allocation of demand cost of service on a non-coincidental basis for the reason that a non-coincidental capacity determination exceeds the experienced maximum utilization of the facilities and, as such, is not representative of the use of the facilities at a time of peak requirement. (47:4965.)

With respect to the second inherent defect, Learned noted that the capacity credit method purports to charge to the firm customers the responsibility for "total available capacity" (representing capacity used by them, plus the unused capacity they create), less a credit amount for the capacity used by the *interruptible* customers when not required by the firm customers. However, he pointed out that:

> This concept has overlooked the fact that it is possible through *diversity* of *firm* loads to operate a pipeline system at close to 100% load factor and thereby have no unused capacity available for *interruptible* service. (47:4966: emphasis supplied.)

He illustrated this by using the hypothetical example of a pipeline with only two *firm* load customers, A and B. In this example, on January 1, customer A took 100 units of gas, and customer B took only 50 units, with total deliveries through the pipeline on that day representing 150 units. On January 2 the situation was reversed, and customer A took only 50 units of gas while customer B took 100 units, with total deliveries again amounting to 150 units. On the remaining days of the year both customers A and B took 75 units each, thereby insuring a 100 percent load factor operating condition for the pipeline. In this example, the non-coincidental peak demand under the capacity credit method would consist of 100 units for customer A, and 100 units for customer B, for a total of 200 units. The "*total available capacity*" under the capacity credit method would therefore represent 200 units times 366 (the number of days in the test year 1956), or 73,200 units. The "*used capacity*" would represent 150 units times 366, or 54,900 units. The indicated "*unused capacity*" available for interruptible customers (*i.e.*, "total available capacity," minus the "used capacity") would be 73,200 units minus 54,900 units, or 18,300 units—despite the fact that the pipeline actually operated at 100 percent load factor, and in fact had no unused capacity available for interruptible deliveries.

The net result in the hypothetical situation illustrated above is that we have a peak day on which the vacated capacity thus made available by customer A, which would be classified as "unused capacity" under the capacity credit method, was actually used not for interruptible deliveries, but for firm customer B—and there was actually no unused capacity available for interruptible deliveries. Nevertheless, the capacity charge to firm customer A would represent (a) used capacity (*i.e.*, actual deliveries), plus (b) a fictitious *unused capacity* figure based on non-coincidental peak demands. Customer A would not receive any capacity credit as a result of firm customer B's use of the vacated capacity thus made available, since Nissel's capacity credit applies only where unused capacity is used by *interruptible* customers (SO and TS service). The same situation

would apply to firm customer B, in connection with customer A's use of the vacated capacity made available by B on a peak day.[37]

As Learned stated in conclusion:

> The capacity credit method of allocation has the effect of overcharging those customers with a poor load factor and/or those customers whose peak-time requirements are different from the system peak-time requirements.
>
> I do not consider it proper to base an allocation of cost of service upon a premise that penalizes a zone with customer diversity or a zone which does not contribute to the system peak in the same magnitude as indicated by their non-coincidental peak-time deliveries. (47:4970.)

Tennessee, in making much the same criticism of the capacity credit method, has correctly characterized it as dealing in "fictitious or phantom unused capacity." (Reply brief, pp. 17–18.) Tennessee emphasizes the fact that this basic error on the part of Columbia's witness Nissel resulted from the latter's failure to give weight to the manner in which Tennessee's system has been constructed since the advent of storage. As noted in detail at an earlier point, the capacity built into the Tennessee system from the source of gas supply up to the storage reservoir is equal only to the *average* daily requirements (or annual average day demands) of the General Service customers, whereas the capacity north of storage is based upon the peak daily requirements of the customers. The difference between such average daily demands and peak demands is met by withdrawals from storage. (53:7093; 67:8813–14.)

During the cross-examination of Columbia's witness Nissel, it was developed that his term "Total Available Capacity" (Exh. 85, Sched. 12, Col. 3), which constitutes the basis for his computation of the capacity charge to the firm customers, admittedly does *not* represent capacity which was available and could physically be met by the Tennessee system on each and every day of the year. (53:7092): Instead, Nissel conceded that it might more accurately be designated as "paid for capacity on an annual basis," or "*billed* annual firm capacity." He further admitted that the classification "unused capacity" in Column (5) could more accurately be changed to "paid but not used capacity," or "billed off-peak capacity." (53:7109.)

The entire situation was summed up in the following colloquy with Nissel:

> PRESIDING EXAMINER: Would it be correct to say that with regard to the figures in Column (5), that another way to state it would be to say that the figures in the column represent a volume which the customer paid for but actually did not use, but this does not mean necessarily that if he had wanted to use it that all of that capacity would have been available for him to use, based on Tennessee's system capacity?
>
> THE WITNESS: That is a correct statement, Mr. Examiner. (54:7134).

The net result of Nissel's use of billed demands derived from maximum day usage multiplied by 366, would appear to be that a General Service customer, for whom facilities are not built to storage on the basis of maximum requirements but rather on the basis of average daily requirements, is charged with "unused capacity" which does not exist. Stating this another way, the amount of "unused capacity" computed by Nissel would appear to represent a purely theoretical figure, which could not actually occur on the basis of the facilities physically in place on the Tennessee System as it existed during the test year. As stated in the Tennessee reply brief (p. 18),

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[37] To state this another way, firm customers A and B would be charged with *"unused capacity,"* even though the pipeline actually operated at 100% load factor and had no unused capacity available for interruptible deliveries.

> Since General Service customers are *billed* on the basis of *peak* demands, but capacity is *installed* for them up to storage on the basis of their annual *average* day demands, it is obvious that Tennessee could not serve all of its customers if they all took gas at a 100 percent load factor. . . . Billed capacity is one thing. Actual capacity is quite another thing.

Still another basic defect in the capacity credit method lies in the fact that it provides a credit to firm customers only in cases where the off-peak capacity created by the latter was used for sales to interruptible customers. (52:7038). As a result, no credit is provided to firm customers who, by reason of their load characteristics, generate the off-peak capacity which is used for storage injections. (52:7038, 7051). This inequity is particularly serious in the case of a system, such as Tennessee, which has large underground storage facilities.

The Mcf-Mile Approach

We now turn to a consideration of the Mcf-mile allocation method, which is advocated in this proceeding by Tennessee, the Commission Staff and the New England intervenors.[39] In its landmark *Northern Natural* decision, Op. No. 281, adopting and approving the Mcf-mile method, the Commission stated:

> * * * it is a simple economic fact that the delivery cost of natural gas increases in close proportion to the length of the transmission line of any given size. Therefore, unless other circumstance are present which outweigh the importance of the length of transmission required to effect delivery, the distance factor is the prime determinant of the cost of rendering service. Since in our view of this record there are no such circumstances present to counter-balance the distance factor, we conclude that the distance of transmission required to effect deliveries at the various points of sale by Northern reflects with reasonable accuracy the relative cost of providing service to its customers. * * * (14 FPC 24)
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> * * * * * * *
>
> * * * we find that there is no such concentration of sales in a single area of the system as would countervail against the arguments of the Proponents and the Staff that the distance of transmission—the mileage of haul—is the primary and controlling factor in the determination of the basic issue here. (14 FPC 22–23)

Columbia contends, however, that the Mcf-mile allocation method was actually regarded as acceptable by the Commission in the *Northern Natural* case only because it there happened to produce a result almost identical to that arrived at under the zone-by-zone (or zone-gate) method presented by the Proponents of zoning: that this similarity in results established that the Mcf-mile method in that case *was* an accurate measure of costs, and this alone made it acceptable. The difficulty with this theory is that the Commission in the *Northern Natural* case, as noted at an earlier point in this decision, expressly rejected the zone-by-zone (or zone-gate) method as being neither sound nor reasonable, on the basis of certain inherent defects which it found in that method itself. Since the Commission thus expressly characterized the zone-gate method as an unacceptable measuring stick, it is difficult to see how it can seriously be contended here that the standard or criterion which made the Mcf-mile method acceptable to the Commission in the *Northern Natural* case was the fact that it produced a result almost identical to that under the discredited zone-gate method. The instant Columbia argument, if drawn to its logical conclusion, would seem to suggest that the Mcf-mile method of allocation could never be

[39] The modifications to the straight Mcf-mile method here proposed by Tennessee and the Staff will be discussed in detail at a later point.

used by the Commission for an allocation of cost among zones on any pipeline system unless the Commission first applied the zone-gate method and found that the costs allocated under both methods were approximately the same. This, of course, would represent another way of saying that the zone-gate method is mandatory under the Natural Gas Act—and that, of course, is plainly not the case.

Columbia further contends that under the mechanics of the Mcf-mile method, if there are no deliveries there is no allocation of cost, irrespective of the size and cost of installed plant (initial brief, p. 43)—*i.e.*,

> * * * it is undisputed that if no gas were transported through a particular facility, no costs would be assigned to such facility. (initial brief, p. 61)

Columbia argues that this illustrates that under the Mcf-mile approach the transmission costs assigned to a given zone depend not upon the transmission costs associated *with the facilities* in that zone, but rather upon the physical volumes of gas transported by such facilities; that the result is to penalize customers in zones where facilities are used at or near maximum efficiency, by assigning to them a part of the cost of facilities in other zones used at a small percentage of maximum efficiency, thus subsidizing the inefficient user of capacity.

This argument, of course, represents a basic attack on the merits of the Mcf-mile approach as such, as applied to any pipeline system, and would have been equally applicable to the use of the Mcf-mile method in the Northern Natural case, Op. No. 281. The Commission there noted and took into consideration the fact that Northern Natural did not represent a uniformly efficient system, in that the annual load factor of estimated 1954 sales in Minnesota (the northernmost part of the Northern Natural system) was lower than the system average for jurisdictional sales, and was in fact the lowest of any state served by that system. (Op. No. 281, p. 19) Yet, although the Commission there recognized the importance of load factor, it did not regard or treat this factor as providing a justification for rejecting the Mcf-mile averaging method.

The basic answer to the instant Columbia contention is that a pipeline company installs facilities for the purpose of rendering a service, and that accordingly costs should be allocated to the *service* rather than to the facilities. The service rendered by Tennessee to its customers is the delivery of specified volumes of gas, over a distance of a certain number of miles. Accordingly, under the Mcf-mile method costs are distributed in such a way as to reflect and give weight to (a) distance, plus (b) the use made of the facilties, measured by peak-day and annual volumes. The Columbia argument indicates a preoccupation with the *facilities*, and an insistence on associating costs with facilities rather than with the service rendered thereon. This viewpoint is, of course, consistent with the zone-gate method, which is basically a segregation of facilities approach, but that approach has been here rejected.

Apart from the above, the Columbia statement that "if no gas were transported through a particular facility, no costs would be assigned to such facility" is rather misleading. The fact is that in such a hypothetical situation the costs relating to that particular facility would admittedly be included in the total Tennessee costs to be allocated among zones. However, since there would be no volume factor associated with such facilities, for use in connection with the Mcf-mile equation, the net result would merely be that these facilities would play no role and would not be used *in computing the allocation ratio* The fact is, however, that in such a hypothetical situation a similar

result would be encountered under the zone-gate method as well. For example, if no gas were transported over a given facility located in the Central Zone, this particular facility would play no role and would not be used in computing the allocation ratio to determine what portion of its cost should be allocated on to the downstream zones. The allocation ratio would be based on the relative peak-day and annual deliveries in the Central Zone, as compared with that for the downstream zones, and under these hypothetical circumstances this particular facility would supply no peak-day or annual deliveries for use in constructing such allocation ratio.

In an effort to demonstrate that the Mcf-mile method is arbitrary and capricious, Columbia has developed and presented here a number of comparative data computations. For example, Columbia contends that the Mcf-mile method is demonstrably unfair to the Eastern Zone and unduly favorable to the New England Zone, as indicated by the fact that total costs allocated to the New England Zone under that method constitute only one-fourth of the cost allocated to the Eastern Zone, despite the fact that investment in the New England Zone was two-and-one-half times, and the pipeline miles even three times, the respective figures in the Eastern Zone. (initial brief, pp. 48 and 49) This comparison is regarded as meaningless, since it completely ignores the relative *volumes* of deliveries in the two zones—this being, as just previously noted, an important factor in allocating costs on the basis of service rendered. Thus, Eastern Zone deliveries in 1956 were 231,938,604 Mcf (Exh. 83, Schedule 5, Column 2, Line 18), which is approximately 6⅓ times the New England deliveries of 36,648,242 Mcf. (Exh. 83, Schedule 6, Column 2, Line 22)

Furthermore, this Columbia complaint is part and parcel of its segregated facilities, incremental approach, predicated on the premise that the customers of a given zone have a vested interest in certain specific portions of the pipeline. That approach has been here rejected on the ground that the Tennessee system is an integrated system, with each part of the system, whether directly or by displacement, contributing to every other part; that all customers should accordingly be charged on the basis of average system-wide costs for each mile of transmission. Under this approach it is not relevant or meaningful to compare the number of miles of pipeline or the average original cost of facilities which happen to fall within one zone as compared with another.

In the same connection, it is important to recognize that the number of miles of pipeline found in a given zone is not necessarily determined by, nor does it necessarily measure the service rendered to the customers in such zone. It results, rather, merely from the manner in which the zone boundaries happened to be set up on the Tennessee system, and represents simply the number of miles which it takes for the pipeline to run from the point where it enters the zone on the upstream side, to the point where it leaves the zone on the downstream side, on its way north to the other zones. For example, the Southern Zone happens to be a long zone running through the states of Louisiana, Mississippi, and Tennessee, and accordingly the number of miles of pipeline in that zone is relatively high. By contrast the Eastern Zone, for historical reasons, became an unsually small zone with a relatively low number of miles of pipeline. This historical fact, however, has no bearing whatsoever upon the relative *service* rendered by the Tennessee system to the Eastern Zone, as compared with other zones.

In a further effort to demonstrate that the Mcf-mile method produces arbitrary and inequitable results, Columbia presented Exh. 122 purporting to show the cost allocated to the New England Zone by the Staff in its Exh. 90 "because of the MMcf-miles within that zone", allegedly amounting to only

$1,253,292, and comparing this figure with the cost "actually incurred" within such zone as shown on Tennessee's Exh. 77, amounting to $5,628,567. In addition, Columbia presented Exh. 125, purporting to show that the differential between the New York Zone rates and the New England Zone rates developed from the costs allocated to those zones under the various Mcf-mile presentations would fall far short of the costs "actually incurred" within the New England Zone, as computed in Exh. 77. (initial brief, pp. 50–52)

Since both of these Columbia comparisons are based upon the purported costs "actually incurred" within the New England Zone as developed in Exh. 77, it is important to understand the background as to how Exh. 77 happened to be prepared and presented in this proceeding. During the early stages of the instant hearing the Presiding Examiner, pursuant to a request by counsel for Consolidated, directed that Tennessee make available to all parties data showing:

> (1) The actual direct expenses, plant and related reserves, and all other charges and credits which would be involved in any determination of Tennessee Gas Transmission Company's cost of service for the calendar year 1956, for the New England Zone formerly served by Northeastern Gas Transmission Company, and (2) an allocation of the indirect expenses, plant and related reserves, and all other charges and credits properly includible in Tennessee Gas Transmission Company's system cost of service for the calendar year 1956 between the New England Zone and the remainder of the system, together with a comprehensive explanation of the principles and methods used in such allocation.

This requirement was based upon and patterned after the accounting condition originally imposed upon Tennessee in the *Northeastern* merger case, *supra*. By orders issued November 1 and December 31, 1957 the Commission affirmed this ruling, on the ground that such information would enable the Commission and all parties to test the accuracy and validity of such allocations as might finally be sponsored by Tennessee or any intervenor in this proceeding. However, the order of December 31 expressly stated:

> For the purposes of this order to Tennessee, it is understood that the cost data and allocation thus presented will not be construed to represent Tennessee's position on cost data or allocation.

In compliance with this order, but under protest, Tennessee prepared and presented Exh. 77, consisting of a segregation of New England direct costs, together with a system-wide allocation of costs up to the New England Zone. (36: 4690–4702) Tennessee witness Davis, who presented Exh. 77, testified that in his opinion the method of allocation there employed was not appropriate for a determination of costs assignable to the New England Zone for rate-making purposes.

It must be borne in mind that Tennessee was asked to provide the Exh. 77 study at an early stage of this proceeding, at a time when the basic question had not yet been resolved as to whether Tennessee's costs should be allocated between zones under an averaging method, or whether instead any one or all of the Tennessee zones should be considered and treated as a separate entity. Since it has now been concluded that the segregation of property approach should *not* be used for an allocation of costs between zones on the Tennessee system, the Exh. 77 study, which does employ a segregation of property approach with respect to those costs identifiable as relating directly to operations within the New England Zone, becomes meaningless. It is quite clear that the Exh. 77 study suffers from some of the same defects as those already outlined

above with respect to the pure zone-gate method. Thus, it does not allocate to other zones any portion of the costs pertaining to the New England facilities used or usable for maximizing storage injections, it does not in any way reflect or give weight to the fact that average-day, rather than maximum-day, pipeline capacity was installed upstream from storage for New England customers. It requires New England to share in all the costs of upstream zones on a rolled-in basis, but not vice versa. Finally, it treats the New England Zone *per se* on an incremental basis, while the remainder of the system is treated on a rolled-in basis—an approach which the Commission characterized as unsound in the *Northern Natural* case, Op. No. 281, as follows:

> We do not believe it either sound or reasonable to allocate costs in part on a system-wide basis and in part on the basis of a segregation of certain properties as the proponents have done. (14 FPC 29)

In view of the conclusions arrived at above with respect to Exh. 77 it is concluded that any studies designed to show alleged inequities and arbitrary results flowing from the Mcf-mile method, by comparing various data with costs "actually" incurred within the New England Zone, as derived under Exh. 77, are without value here.

In one of its basic criticisms of the Mcf-mile approach, Columbia contends that the allocation method here adopted must be one which reflects as accurately as possible "the actual cost" incurred in serving the customers in each zone; that, unlike the Northern Natural system, there is a great variation in average unit costs per Mcf-mile among the different zones on the Tennessee system, caused by a great number of factors such as variations in pipe size, differences in load factor, and the like; that the Mcf-mile method, which uses an averaging approach, fails to reflect or account for such differences and therefore does not reflect "actual cost" incurred for each zone; that the zone-gate method is the only allocation method which does result in the determination of the "actual costs" for each zone, and accordingly the zone-gate method is the only one providing the Commission with an objective standard against which to judge whether the rates filed by Tennessee for each zone are in fact fair and reasonable.

The basic answer to this contention lies in the controlling philosophy developed at an earlier point in this decision—*i.e.*, that although it is recognized that unit costs of transmission in one area may be different from those in another, the overriding consideration here is that Tennessee constitutes a single, integrated pipeline system, with each part of the system contributing to every other part; that accordingly costs should be averaged among all zones, and all customers should pay on the basis of average system-wide costs for each mile of transmission.

In addition, it should be noted that this Columbia thesis rests upon a shaky assumption in that the zone-gate method itself does not in fact really determine for and allocate to each zone the "actual costs" incurred to provide service therein. There are numerous situations arising under the zone-gate method where the costs of a particular facility are charged to a given zone, not because of or on the basis of the extent to which such facility is actually used for service to such zone, but merely because the geographical location of the boundary line resulted in the facility falling within the zone in question. This is particularly true with respect to the cost of service associated with property located near the downstream boundary of each zone. The problem is well illustrated by reference to Compressor Station No. 200, which is located at the downstream end of the Central Zone. Although only a very small amount

of gas compressed by Station No. 200 is actually delivered in the Central Zone, the cost of service associated with that station is allocated to all customers in that zone as if it in fact compressed gas for all customers in the zone. (68:8932–3)[39] Under the zone-gate method, solely for the historical reason that this compressor station happens to fall within the artificially prescribed boundaries for the Central Zone, the costs associated with that station are distributed between that zone and all downstream zones on the basis of their relative ratios of peak-day and annual deliveries. This allocation is thus based upon the total volumes of gas delivered to the Central Zone on the peak-day, and annually, and has no relationship whatsoever to the contribution which Compressor Station No. 200 makes to the service rendered to that zone. On the other hand, if the boundary line of the Eastern Zone had instead been fixed at a point south of Compressor Station No. 200, so that this station fell within the Eastern Zone rather than the Central Zone, it is clear that under the zone-gate method none of the costs associated with that station would have been assigned to the Central Zone. This variation between actual use and the ratio of cost assigned under the zone-gate method is not peculiar to compressor stations. The same type of variation exists with respect to all transmission facilities within a rate zone. For example, although the actual use of transmission mains for deliveries in the zone in which they are located declines as the gas moves downstream, the cost of service related to such mains is allocated on the basis of a zone-wide allocation ratio. (68:8934)

It is, of course, true that similar results may occur under the Mcf-mile method as a result of the averaging process within the zone, which is also inherent in that method. However, the effect of such situations is minimized and counterbalanced to some extent, under the Mcf-mile approach in view of its use of system *average* costs. The situation cannot be viewed so charitably, however, with respect to the zone-gate method since the basic virtue claimed for that method is that it allegedly determines for and allocates to each zone the "actual costs" incurred to provide service therein. The situations discussed above illustrate the fallacy of the proposition advanced by the zone-gate proponents that their method "assured that costs incurred in any part of the system are borne by those customers who are responsible for such costs." (47:5203) In view of the fallacy of this basic assumption, it is difficult to see the justification for adopting a method as complicated as the zone-gate approach, with all its related problems, in preference to the more simple and direct Mcf-mile method.

Entirely apart from the above, the basic assumption by the proponents of the zone-gate method that it does result in the determination of "actual costs" for each zone claims too much. Both Columbia and Consolidated here purport to find as a "fact" the "actual cost incurred" within each zone. It is obvious, however, that any such finding under the zone-gate method is not a "fact" but merely a conclusion inferred from and depending upon numerous allocations, including allocations on a system-wide average basis of substantial system-wide costs (treated as "joint" costs), relating to cost of purchased gas, storage costs, and administrative and general expense. In addition, under the zone-gate method a uniform depreciation rate, a uniform rate of return and a uniform income tax cost are assumed for each of the six zones on the Tennessee system, without any attempt to arrive at separate and distinct factors for each zone as if it were in fact a separate operating entity.

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[39] The only condition precedent to such a situation is that there be a single customer within that zone between such facilities and the downstream zone boundary. (55:7298–7303)

Columbia and Consolidated Contention That Mcf-Mile Method Should Not Be Adopted for Tennessee System in View of Unfavorable New England Zone Characteristics

Although the Mcf-mile method, as here advocated by the New England intervenors, and by the Staff and Tennessee in modified form, results in higher rates to the terminal New England Zone than to any other zone, because of the great weight given to the factor of distance, Columbia and Consolidated contend that this is not enough; that the factor of distance alone was properly regarded as controlling on the Northern Natural system in Op. No. 281 because the factors such as load distribution, load factor and pipe size were allegedly highly uniform on that system, and accordingly no other circumstances were there present which outweighed the importance of the length of haul; that on the Tennessee system, however, there is a great variation between zones with respect to such factors, and *particularly with respect to the New England Zone;* that distance alone thus is not the controlling consideration on the Tennessee system, but an allocation method must instead be adopted which gives adequate weight to the unfavorable load distribution, load factor and pipe size characteristics of the New England Zone, and which accordingly allocates to that zone a substantially higher percentage of costs than would be allocated under the Mcf-mile method.

It will be seen that this argument is basically an attack on the New England Zone. Columbia stresses the following as unfavorable characteristics of the New England Zone, which must be given controlling effect here:

(1) *Pipe Size.* It is emphasized that there is a wide variation in pipe size, particularly resulting from the fact that the service rendered in New England is allegedly a lateral-type service. While the diameter of only 17 percent of Tennessee's total transmission pipelines is under 20 inches, in the New England Zone 74 percent is under 20 inches, with 50 percent of the pipe having a diameter of 10 inches or less. (Exh. 83, p. 8; appendix to initial brief, Tab C)

(2) *Load Factor.* It is further stressed that there are wide variations of load factor among the various zones; that the total system load factor averages 87.2 percent, load factor in the Eastern Zone was 99 percent, and load factor in the Northern Zone (due to interruptible sales) was approximately 106 percent—whereas the load factor in the New England Zone was only 48.6 percent. (48: 5621; Exh. 97A, p. 13)

(3) *Excess Capacity.* It is contended that there was substantial excess capacity in the New England Zone during the test year.

Columbia contends that the cumulative effect of these factors is that unit costs vary substantially from zone to zone on the Tennessee system, and that unit costs are substantially higher in the New England Zone than in any other zone on the entire system. (initial brief, pp. 8–10, 24)

We now turn to a detailed consideration of these particular unfavorable characteristics of the New England Zone, as stressed here by Columbia.

(1) *Pipe Size*

The New England system, previously owned by Northeastern, consists primarily of a 24-inch pipeline approximately 139 miles in length, extending across the state of Massachusetts, a 16-inch line approximately 112 miles long, extending from Tennessee's facilities at the Connecticut-New York state line near Greenwich, Connecticut, to such 24-inch line near Springfield, Massachusetts, and numerous laterals in Connecticut, Massachusetts, Rhode Island, and New Hampshire, ranging in diameter from sixteen inches down to three inches.

Columbia contends that these laterals are used to deliver gas to city-gate measuring stations of Tennessee's New England distribution customers, a service allegedly not rendered in any other zone; that customers in each of Tennessee's

other zones were required to construct pipelines from their distribution systems or from other facilities to delivery points on Tennessee's main pipelines; that this different operation in the New England Zone resulted from the fact that the New England system was originally designed by Northeastern to provide a semi-distribution service. (initial brief, p. 29) The suggestion that customers in each of Tennessee's other zones have been compelled to assume more substantial burdens than those in the New England Zone in order to take gas from the Tennessee pipeline has not been satisfactorily developed in this record, and is strongly disputed by the New England intervenors. However, this point is not regarded as material since none of the parties, in any event, dispute the basic fact that a larger percentage of Tennessee's pipeline mileage in the New England Zone consists of small diameter pipe than is true for the Tennessee system as a whole.

This isolated fact in itself, however, is not regarded as controlling or determinative here. In the first place, in considering the extent to which the presence of the higher-unit-cost, small diameter pipe should be given weight in connection with the allocation of costs between zones, the critical consideration should not be the mere *physical location* of the small and large diameter pipe. The fact is that the large diameter lines in the upstream zones are not required merely for deliveries in those zones, but are used to transport gas from the major sources of supply into the entire system, including the New England Zone. In other words, those lines find their justification in the volumes which must pass through such pipe destined for all downstream markets, including the New England Zone. Under these circumstances, it would not be realistic or fair to take the position that credit for the low-unit-cost characteristics of transmission over the large diameter pipe should go only to the upstream zones, and that the New England Zone should not be credited with any of those benefits or advantages.

As Tennessee witness Davis testified:

> Q. Suppose the transmission system consists of pipes of different sizes in various zones. Will the actual cost of transmission in such system vary from zone to zone with the size of pipe used?
>
> A. It isn't quite that simple, Mr. Rosan, for the reason that as gas goes through one zone with a certain diameter of pipe, the gas in the pipe in that zone is destined to customers in the zone in which that pipe is located, *as well as to customers in zones beyond.*
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> * * * * * * *
>
> A. Yes, sir; unit cost of gas transmission through larger pipe is less than the unit cost of gas transmission through smaller pipe. That doesn't mean that you can suis sponte just allocate the large pipe to one zone and the small to another. (29:3978–79) [Emphasis supplied.]

In addition, New England intervenor witness Tippy contended that the Columbia comparison of relative percentages of haul *within* a zone through smaller diameter pipe do not constitute a meaningful comparison for cost allocation purposes. He stated:

> * * * the cost of delivering gas to a particular group of customers on a pipeline system, to the extent that it depends on pipe size, depends not on the pipe size existing only within the zone in which those customers are located, but on the pipe sizes all the way from the source of gas supply to the customer's delivery point. (62:8169)

Based on this theory, Tippy prepared his own comparative study (Exh. 120) showing the extent to which service is rendered in the New England Zone over pipe under ten inches, with similar comparative figures for the Northern Natural

zones which were the subject of Op. No. 281. This Tippy study differs from Columbia's comparative data with regard to small-diameter pipe in two important respects:

(a) Exh. 120 compares not merely the mileages of different sizes of pipe, but also reflects and combines the *volumes* of gas delivered over such mileages. It develops "Average Miles of Haul" over pipe under 10 inches, and pipe 10 inches and over—but such "average miles of haul" actually represent

> * * * a weighted average mileage of haul which is the result of taking the MMcf miles hauled through these different sizes under 10-inch and over 10-inch and dividing them by the volumes delivered in the zone.[40] (63:8284)

And the comparative percentage figures finally derived are based upon the MMcf miles through small diameter pipe, in relation to the total MMcf miles over all sizes of pipe. (63:8281)

(b) In addition, Exh. 120 reflects *not* the comparative MMcf mile data *within* the relevant zones, but rather the MMcf mileages all the way from source of supply to customers' delivery points.

Following this procedure, Tippy found that the "average miles of haul", as thus defined, through pipe under 10 inches for the New England Zone was 6.57 miles, or 0.36% of "average miles of haul" for that zone over all sizes of pipe. With respect to the Northern Natural system, using the same procedure, he found "average miles of haul" through pipe under 10 inches for Zone 1 at 8.47 miles or 2.14%, for Zone 2 at 6.76 miles or 1.24%, and for Zone 3 at 2.24 miles or 0.29%. From this he concluded that in both the Northern Natural system and the Tennessee system the percentage of the total haul through pipe under 10 inches in diameter was very small; that the average haul for New England Zone deliveries through pipe under 10 inches was comparable in mileage with Northern Natural's Zone 2, and as to per cent of total haul was comparable with Northern Natural's Zone 3. Tippy then concluded:

> Consequently, even if we assume that the unit cost through this smaller pipe is substantially more than the unit cost through the larger pipe, the length of haul through the smaller pipe is so small as to be without significance in determining the method of cost allocation which is appropriate * * *. I conclude further that the attempt to distinguish the Tennessee system from Northern Natural with respect to its suitability for application of the Mcf-mile method on the basis of pipe size, is invalid and misleading. (62:8171)

Columbia contends that witness Tippy's Exh. 120 comparison is meaningless on the ground that it merely reflects the *amount* of gas transported through small diameter pipe, and does not reflect the miles of pipe or the costs related thereto (reply brief, p. 33). In weighing this objection, it is important to bear in mind that our real objective here is to determine whether the small-diameter pipe situation in the New England Zone represents such a significant and controlling factor as to outlaw the use of anything other than a zone-gate allocation method for the Tennessee system. Our primary interest in pipe size here lies in the extent to which it affects the cost of delivering gas in the New England Zone, as compared with that for the other zones. But the true picture of the cost for delivering gas in the New England Zone is obtained only by directing our attention to the total mileage of pipe used to carry gas *from the source of supply* to New England delivery points. Accordingly, in order to keep this problem in balance and to avoid distortion, we must consider the small-diameter pipe which is physically located in the New England Zone only in

[40] *I.e.*, by the total volumes delivered in that zone over all sizes of pipe.

terms of the weight it plays in the total miles of haul from the source of supply to the New England delivery points. Furthermore, for similar reasons, a balanced picture can be obtained only by considering and giving weight to the *amount* of gas transported through small-diameter pipe in the New England Zone, and not by directing our attention merely to the *miles* of small-diameter pipe in that zone, viewed in a vacuum.

The admitted fact that a larger percentage of Tennessee's pipeline mileage in the New England Zone consists of small diameter pipe than is true for the Tennessee system as a whole, constitutes an unfavorable characteristic of the New England zone which should be taken into account and adjusted for in some appropriate manner. However, under all the circumstances outlined above, it is concluded that the mere physical presence of such small-diameter pipe in the New England Zone is not so significant or controlling as to outlaw the use of an Mcf-mile allocation approach for the Tennessee system.

(2) *Load Factor*

As noted at an earlier point, the Staff derived a load factor of 48.6 percent for the New England Zone, by relating the deliveries to that zone during the Staff's selected three-day peak of January 16, 17 and 18, 1957 to annual deliveries to the New England Zone during the test year 1956. (Exh. 97A, Sched. 5, Sheet 1, Column 6) This low load factor for the New England Zone compares with a total Tennessee system load factor averaging 87.2 percent—a comparison which is of interest here since it is axiomatic that, all other factors being equal, the lower the load factor the higher the unit cost of service.

The New England intervenors contend that the Staff's derived load factor of 48.6 precent for the New England Zone is unreasonably low, as the result of two alleged errors in the Staff computation which are discussed at length in the New England reply brief. (pp. 18–21) It is contended, first, that in calculating the New England Zone load factor the 1957 three-day peak used by Staff should not have been related to 1956 annual volumes, but instead should have been related "to those annual volumes which will result, or flow from, the establishment of such peak." It is further contended that in making this load factor computation the Staff erroneously included in the peak-day volumes PS–G gas which was sold at that time merely as a temporary, incremental service; that the Commission, subsequent to the test year, denied Tennessee the authority to render such Peak Srevice on a permanent basis;[41] that accordingly the load factor in the New England Zone will not in the future be adversely affected by non-existent Peak Service sales. The New England intervenors contend that if corrections were made for these two alleged errors, the load factor derived for the New England Zone would be "substantially higher than 65 percent".

It will not be necessary here to resolve these contentions as to the precise level of the load factor in the New England Zone, since it is concluded that the load factor of that zone under *any* method of computation is admittedly substantially lower than that of the other zones on the Tennessee system.

Both the New England intervenors and Tennessee take the position that the problem of low load factor in the New England Zone is adequately accounted for under the Mcf-mile approach, by virtue of the fact that Tennessee gas is sold under a two-part demand-commodity type of rate schedule, which allegedly compensates the high load factor customers (Tennessee initial brief, p. 35; reply brief, p. 9). This view reflects a thought similar to that expressed by the Commission in its Opinion and Order Denying Rehearing, *In the Matter of El Paso Natural Gas Company*, Op. No. 326–A (22 FPC 659, October 8, 1959). In

[41] Commission order issued January 28, 1959, *In the Matter of Tennessee Gas Transmission Co., et al.*, Docket No. G–11107, *et al.*, 21 FPC 70.

that case the Southern California intervenors objected to the Commission's application of the Atlantic Seaboard classification formula to El Paso, arguing that the high load factor customers, such as the California customers, made greater use of the capacity provided for them and were penalized by requiring them to pay part of the costs incurred for the less efficient users of the capacity. The Commission rejected this argument, stating:

> We think that the heavy users of the facilities should bear a greater share of the capacity costs than the light users. *Of course, the higher the load factor, the lesser the unit cost to the purchaser of gas.* (22 FPC 665) [Emphasis supplied.]

It is concluded here that the relatively low load factor of the New England Zone does constitute an unfavorable characteristic which should be taken into account and adjusted for in some limited manner. However, it is not regarded as so significant and controlling as to outlaw the use of an Mcf-mile approach in this proceeding. In this connection, it is relevant to point out that in the *Northern Natural* case, Op. No. 281, where the Mcf-mile method was adopted, the Commission's order decreased the amount of the zone rate differentials resulting from a strict application of that method in such a way as to substantially benefit the terminal zone (Northern Natural Zone 3). This was in spite of the fact that the load factor in the state of Minnesota (where over 80 percent of the jurisdictional sales in the terminal zone were made) was the lowest on the Northern Natural system. Under the circumstances, it seems obvious that the Commission in that case did not regard the element of unfavorable load factor as presenting a controlling or key problem which should be permitted to dominate the disposition of the allocation question.

It is also o finterest, in connection with this problem, to observe the manner in which the Commission viewed the load factor problem in the Tennessee peaking service case, Docket No. G–11107, *supra*. In its order issued January 28, 1959 in that proceeding, the Commission rejected the Tennessee request for permanent authorization of its Peaking Service, and directed that Tennessee include as a part of its next major certificate application a firm proposal for the full incorporation of its underground storage facilities in the overall operation of its pipeline system, and the rendition of its services on a fixed and certain basis in a manner which would secure the maximum benefits of the storage equitably to all its customers. The Commission then stated:

> We think that this would possibly entail, with respect to Tennessee's Peak Service, the development of a storage service generally comparable to that Tennessee presently renders in New York.
>
> * * * * * * *
>
> Of course, the rates, terms and conditions of this service would have to be designed by Tennessee responsive to the New England market. While the rates should be fair and nondiscriminatory, they should be sufficiently low to assure the availability of the service in helping to meet the needs heretofore met by the Peak Service denied by this order. *Further, it appears that Consolidated Edison Company of New York, Inc., and other companies in the New York zone now purchase gas from Tennessee at virtually 100 percent load factor to be stored for subsequent withdrawal when needed. Because their operations are varied and extensive, sales at this load factor do not unduly burden such companies. However, many of the New England companies with less extensive and diverse operations could not feasibly take gas on a comparable load factor. The rates and service devised by Tennessee in accordance herewith should allow for such material differences in operating conditions.* (21 FPC 81) [Emphasis supplied.]

Thus, the Commission clearly expressed the view that the New England load factor problem should simply be recognized as one of the facts of life, to be allowed for in designing rates for the New England Zone, rather than treating it as the basis for imposing severe penalties, rate-wise, upon that zone.

(3) *Excess Capacity*

Columbia stresses, as one of the particularly unfavorable factors in the New England Zone operation, that there was an unusual amount of excess capacity in that zone during the test year 1956. This contention is based entirely upon certain testimony presented by its witness Nissel, who rested his conclusions exclusively upon a study of certain testimony given in a Northeastern certificate proceeding, Docket No. G–1267, on January 29, 1951, prior to the Northeastern merger case.[42] The testimony in question related to the design and planned capacity of the proposed Northeastern laterals in the New England Zone, plus an inference contained therein as to the "corresponding reserve capacity" which would be produced in the main body of that system by the 24-inch transmission line for which certification was there sought. Using this 1951 testimony as his point of departure, and comparing it with the maximum daily volume of 177,000 Mcf actually delivered in the New England Zone in the test year 1956, Nissel concluded that "If the market had been there, and all the plant had been used fully", (52:6057) he thought that Tennessee "*might* have been able to deliver" more than twice this latter volume, or over 354,000 Mcf per day. He therefore concluded that the New England Zone had more than 50 percent of excess capacity in the test year.

Nissel admitted, however, that he had not himself made any capacity studies, other than these particular comparisons. (52:6056) He further qualified his conclusion as follows:

> A. * * * I haven't made a computation, mind you, but from all the information in front of me——
>
> Q. With the facilities existing in 1956?
>
> A. I don't think that this is impossible, no.
>
> Q. Do you know whether this could have been done?
>
> A. I just said, Mr. Werner, that I didn't make a flow computation. * * *
>
> * * * * * * *
>
> A. * * * It is my understanding—my understanding is probably going a little too far—*it is my impression* that for a period equivalent to the period in which they delivered 177,000, that system *might* have been capable of delivering twice that much, yes. (52:6057–58) [Emphasis supplied.]

To add to the confusion on this subject, New England witness Tippy testified that in his opinion there was excess capacity *virtually all through Tennessee's system* during the test year—this conclusion being based upon his study of the flow diagrams presented in an earlier Tennessee certificate case, Docket No. G–9448, involving additional facilities which were completed and put in service in October, 1956. (50:5855–56) Tippy further testified that on a system like Tennessee's, which is constantly expanding, the existence of excess capacity in varying amounts on the system at almost any time is the rule rather than the exception. (62:8156) Based on this testimony, the New England intervenors draw a conclusion quite the reverse from that stressed by Columbia, *supra*. They start with the assumption, based upon the Tippy testimony, that there was excess capacity all along the Tennessee system during the test year. Based

[42] Docket No. G–1267 was the proceeding where Northeastern sought authorization to substitute 144 miles of 24-inch pipe for the same length previously authorized, and to substitute larger sizes of pipe in five of the previously authorized lateral lines.

upon this assumption, they contend that under the zone-gate method the New England Zone is charged with a percentage of the costs associated with excess capacity *in the upstream zones*, without regard to the purpose for which such upstream facilities may have been constructed—*i.e.*, even though, by way of a suggested hypothetical example, it might be clear that such excess capacity resulted solely from Tennessee's effort to provide service to an upstream customer. (New England initial brief, pp. 22–23)

The totally unsatisfactory state of the evidence in the instant record with regard to the question of excess capacity in the New England Zone, and in any other part of the Tennessee system, becomes clearly evident when reference is made to the really exhaustive study which was made of the excess capacity issue in an earlier Tennessee certificate case, Docket No. G–5259. That study made it clear that we have here no simple problem which can satisfactorily be resolved by the type of elementary calculations and comparisons which Columbia witness Nissel presented on this subject in the instant proceeding. In the initial decision issued by this Presiding Examiner in Docket No. G–5259, it was concluded that no reliable conclusions could be reached on the subject of the existence of excess capacity on the Tennessee system in the absence of a careful and exhaustive Commission study of that system and its operations, directed expressly to that specific problem, and that the comprehensive presentation made by the parties in that proceeding did not meet this standard. It seems obvious, therefore, that it would be improper in the instant proceeding, where no real excess capacity study of any type has been presented, to draw any conclusions as to the existence of substantial excess capacity during the test year in the New England Zone as compared with other zones (as contended for by Columbia), or to draw any conclusions as to the existence of excess capacity throughout the Tennessee system (as contended for by the New England intervenors).

It is concluded here that the specific relatively unfavorable characteristics of the New England Zone operation outlined above should not be ignored, and that some limited type of adjustment should accordingly be made to the straight Mcf-mile allocation approach in this proceeding, so that the costs allocated to the New England Zone will reflect in some limited manner the excess costs reasonably attributable to those peculiar characteristics. It is further concluded, however, that the zone-gate method, as here presented by Columbia and Consolidated, over-corrects for the New England Zone situation and goes far beyond this proper objective. The views strongly expressed by the Commission in its order issued January 28, 1959 in the Tennessee peaking service case, Docket No. G–11107, are of the greatest interest and significance in this connection. Although that decision dealt with a Tennessee request for permanent authorization of its Peaking Service, the Commission language quoted below expressed a basic policy and point of view which cannot reasonably be reconciled with the rationale of the zone-gate approach as presented in the instant proceeding. The Commission stated, in its G–11107 decision:

> Although we here deny permanent authority for the presently proposed Peak Service, we may properly consider whether some other service can be made available by Tennessee to meet the special natural-gas needs of the public in New England, and what substitute service should be made available on an interim basis. The purpose, among others, of this Peak Service has been to develop an increased market for natural gas in this region. This is a sound and realistic purpose. *It is vitally necessary to the financial stability and operating efficiency of the entire system that the loads on this farthest extension of Tennessee's system be built up and maintained.*

Clearly, the best interests of all of Tennessee's customers are best served if the considerable investment required to bring gas several thousands of miles into the Northeastern United States is supported by those customers who also benefit from it. But without the loads, these customers will never be able to support it. It is in the public interest, moreover, to secure the benefits of natural-gas service to this fuel-hungry region of the country, if it can be done on a reasonable and economic basis, just as is true in the case of other sections similarly handicapped by a lack of native fuel resources. (21 FPC 79)

* * * * * * *

We think that this would possibly entail, with respect to Tennessee's Peak Service, the development of a storage service generally comparable to that Tennessee presently renders in New York.

* * * * * * *

Of course, the rates, terms and conditions of this service would have to be designed by Tennessee responsive to the New England market. *While the rates should be fair and nondiscriminatory, they* should be sufficiently low to assure the availability of the service in helping to meet the needs heretofore met by the Peak Service denied by this order. Further, it appears that Consolidated Edison Company of New York, Inc., and other companies in the New York zone now purchase gas from Tennessee at virtually 100 percent load factor to be stored for subsequent withdrawal when needed. Because their operations are varied and extensive, sales at this load factor do not unduly burden such companies. However, many of the New England companies with less extensive and diverse operations could not feasibly take gas on a comparable load factor. *The rates and service devised by Tennessee in accordance herewith should allow for such material differences in operating conditions.* (21 FPC 81)

It is concluded that the adoption of the Columbia and Consolidated zone-gate approach, which imposes severe penalties, rate-wise, upon the New England Zone, would be inconsistent with the philosophy thus expressed by the Commission in the Tennessee peaking service case. It is further concluded that the adoption of an Mcf-mile approach, adjusted in some reasonable and limited manner to account for the unfavorable New England Zone characteristics discussed above, but exercising some reasonable restraint as to the burden to be imposed upon that zone, would be entirely consistent with the Commission viewpoint expressed above.

Two different types of proposals have been presented in this proceeding for such an adjustment to the straight Mcf-mile approach—one by the Commission Staff, the other by Tennessee. The Tennessee method allocates $739,598 less to the New England Zone and $568,831 less to the Eastern Zone than the Staff method. Both methods allocate substantially less to the New England Zone and substantially more to the Eastern Zone than the zone-gate methods advocated by Columbia and Consolidated.[43]

The Staff's Adjustment to Mcf-Mile Allocation to Reflect Unfavorable New England Zone Characteristics

Applying its Mcf-mile method, the Staff initially derived allocated costs for the New England Zone which were $1,546,779 less than the test year revenues

[43] The Tennessee method allocates approximately $4.5 million less to the New England Zone and almost $6 million more to the Eastern Zone than the Columbia method; and $2.3 million less to the New England Zone, plus $3.8 million more to the Eastern Zone than the Consolidated method.

received from that zone at the Docket G–5259 rates. Similarly, the allocated costs derived for the New York Zone were $768,192 less than the revenue levels for that zone under the G–5259 rates. Thereafter, in preparing the Staff's rate exhibit, Exhibit 97–A, Staff witness Drescher, instead of using the allocated costs for these two zones, used the higher dollar amounts of revenues at the G–5259 rates as the number of dollars to be recovered by the proposed rates for those zones. At the same time, the difference between the initial allocated costs and such G–5259 levels for the New England and New York Zones was distributed to the remaining four zones, and to the transportation services, as a credit to their allocated cost of service. (Exh. 97–A, Schedule No. 4, Sheet 1, and Schedule No. 5, Sheet 1; 47:5450–51.)

Drescher's initial explanation of the rationale for the above adjustment, given in the course of his direct testimony on May 12, 1959, was as follows:

> Q. Why did you use the revenue levels at Docket No. G–5259 rates as the basis for rates in the New York and New England Zones rather than the allocated costs?
>
> A. The Commission's order issued October 17, 1957, in Docket No. G–5259, determined Tennessee's cost of service and prescribed rates, based upon such costs, as "* * * the just and reasonable rates * * *." In this proceeding under Docket No. G–11980, the staff's exhibits show that an overall deficiency in revenues exists.
>
> In view of the Commission's prior action, and since it appears that the company is now in need of additional overall revenues, it is my opinion that as a matter of practical rate making it would be better to work with the net deficiency in revenues and make it up in the rates for the sales and transportation services which, according to the cost allocation exhibit, caused the deficiency. (47:5451–52)

Drescher's next explanation of the above adjustment took place a few days later during the course of cross-examination by counsel for the New England intervenors. The latter inquired as to whether Drescher had any basis beyond the Commission's G–5259 order which he felt impelled him to establish rates for the New York and New England Zones at levels higher than the costs which had originally been allocated by the Staff to those two zones. Drescher replied:

> A. Well, with respect to the New England Zone, I believe that the dollars of cost which are reflected in the cost allocation do not represent the level of cost which I would use for rate making purposes primarily due to the fact that they do not reflect an adjustment, I think, that is proper due to the *low load factor* in New England.
>
> There was idle capacity in New England, stemming from low load factor. (50:5778) [Emphasis supplied.]

He stated that an adjustment should be made for such idle capacity, since it had the effect of increasing the cost of providing service to the customers in the New England Zone. (59:5771) Drescher then explained that he had made "a rough study and * * * a rough adjustment" for this load factor situation in the New England Zone, amounting to $1,018,774. (50:5778; 59:7836) He further explained that this single adjustment had the effect of raising the allocated cost level for the New England Zone to a point in between the cost figure initially allocated to that zone and the higher G–5259 rate level; that, for the reasons outlined in his original direct testimony, he concluded that it was

> * * * not appropriate in my opinion to prescribe a rate reduction in two areas of a system at a time when you are prescribing a rate increase elsewhere and the company is in general need, or the company has an over-all general deficiency * * * (50:5779)

that accordingly in order to avoid this result, he used the G–5259 revenue levels as the basis for "the so-called rate making" in the New England and New York Zones.

The third stage in witness Drescher's explanation of the above adjustment occurred at a still later hearing session during the course of his cross-examination by Columbia counsel. At this point, he repeated his previous explanation with regard to the necessity of an adjustment to reflect the idle capacity stemming from the low load factor in the New England Zone. (59:5771) However, in response to a question by the Presiding Examiner as to whether, as a result of this single adjustment, the rates derived by him for the New York and New England Zones would in fact match the costs as allocated to those zones, Drescher replied:

> Well, essentially that is right. But I have to add something to it in order to make that about 100 percent correct. (59:7774)

He then proceeded, for the very first time, to explain that in addition to his $1,018,774 load factor adjustment for the New England Zone, he had also added a 3 percent adjustment for the New York Zone amounting to $768,192, and a 3 percent adjustment for the New England Zone amounting to $527,991, for the purpose of reflecting two other elements which the Commission in the *Northern Natural* zoning case, Op. No. 281, had discussed as elements affecting the cost of hauling gas—*i.e.*,

> The first one is the load distribution, that is, how is the load concentrated. And the second one is the volume of gas in the various markets of Tennessee because for any given length of pipeline, the larger the line, the lower the unit cost of gas, and the larger the quantity or volume of gas which you sell, it would mean that you would have a larger diameter pipe, which would result in lower over-all unit cost of gas. (59:7775–76)

He stated:

> * * * what I did was to assume that three percent would be a reasonable level to use to reflect these two other elements. (59:7775)

However, he added:

> But basically to me the element of distance is the primary element which is to be considered. (59:7776)

In Drescher's final capitulation, he explained that he had started out with the Staff's original allocated cost figure of $17,807,235, allocated to the New England Zone under the straight Mcf-mile method; that he had then added his first adjustment, for load factor, amounting to $1,018,774, producing a total of $18,826,009; that he had further added to this "a judgment adjustment * * * which brings it up to the revenue levels at 5259 rates." (59:7832) In response to further interrogation by the Presiding Examiner, Drescher then made the following further explanation:

> Now, it is true that, with respect to the adjustments other than the adjustment for the idle capacity stemming from low load factor, I had to use a judgment there, because I know of no method by which you can sit down and calculate in dollars and cents the quantity of dollars to be added to

the demand-mile commodity mile type of allocation in order to reflect the two factors.

* * * * * * *

THE WITNESS: It was a judgment, I backed into it, knowing what the figure was, I had the figure for the New England Zone with the adjustment for load factor, I knew what the revenue levels were at the 5259 rates, the difference was approximately a half million dollars, and it appeared to me, based upon judgment, that that represented a reasonable level, three percent is what the figure is, a reasonable level to attribute to that particular adjustment. (59:7833)

* * * * * * *

As I said, I simply do not know how to sit down and calculate in terms of dollars and cents the adjustment for two of the items, it has to be judgment, there is no way I know of—maybe a different engineer could do it, but I do not know how to do it. (59:7835)

A mere recital of the above difficulties, so frankly described by the Staff witness, is sufficient to indicate the unsatisfactory basis for these particular adjustments as calculated by the Staff. No showing whatsoever was made in the record as to the *method* used by witness Drescher to compute his adjustment in the amount of $1,018,774, based on the New England load factor situation. It is true that Drescher explained that he did have some work papers relating to this particular adjustment (50:5779–80), and at a later point he testified that his adjusted figure "is in a work paper distributed about ten days ago." (59:7826) The Staff brief makes a point of the fact that "This study was furnished to the parties and was not challenged by them." (initial brief, p. 29) However, if the Staff wishes to rely upon the load factor adjustment described above, the burden was on the Staff to explain and support, on the record, the method used for the derivation of that adjustment. In view of the total absence of such a showing by the Staff, there was nothing in the record for the parties to challenge, and we are left without any basis for understanding or evaluating the manner in which the Staff calculated this particular adjustment. It should further be noted that the New England intervenors did, in any event, vigorously challenge and disagree with the end result of this Staff calculation.

With respect to Drescher's second adjustment to reflect the elements of load distribution and volume of gas sold, the Staff witness admittedly found it impossible to calculate any measured amount for these adjustments, but instead simply assigned to them the additional dollars still required to bring the costs allocated to the New England and New York Zones up to the level of the G–5259 revenues for those zones. In this connection, it is of interest to note that the adjustment used by Drescher for the elements of load distribution and volume represented an identical, flat 3 percent adjustment in the case of both zones—despite the fact that load distribution and volume of sales for the New York Zone were considerably higher than for the New England Zone, and despite the fact that the small-diameter pipe factor which is characteristic of the New England Zone is not applicable to the New York Zone. It is also of interest to note that although load distribution and volume of sales for the New York Zone in the test year were *higher* than in the Central Zone, Drescher proposed no such adjustment for the Central Zone.

Under all these circumstances, it seems clear that the controlling factor determining the dollar level of the adjustments made by the Staff to the New England and New York Zones for the elements of load factor, load distribution, and volume of sales, was the Staff's determination that the costs initially allocated to those two zones should be raised to the G–5259 revenue levels. The Staff's

rationalization for this position was that Tennessee appeared to have an over-all general deficiency; that, without the adjustments referred to above, the Staff would have been in the position of recommending a rate reduction for the New England and New York Zones, while at the same time recommending a rate increase for the remaining four zones, and this was regarded as inappropriate. This rationale, however, is *not* persuasive. In the first place, it should be noted that the trial and determination of the dollar cost of service issues in the instant G–11980 proceeding has been deferred, by Commission order, to a later stage; that until such determination is made, there is no way to estimate whether the failure to make an adjustment in the amounts here proposed by the Staff would actually result in a rate *reduction* for the New England and New York Zones. Furthermore, the basic problem before us here is to determine which allocation method should be approved as the most reasonable and appropriate for the Tennessee system, in order to comply with the requirement of the Natural Gas Act that all rates and charges must be "just and reasonable", and that such rates and charges must not be "unduly discriminatory and preferential". (Secs. 4(a) and 5(a)) It is difficult to see how the hypothetical problem here envisaged by the Staff can properly be converted into a measuring-stick for the meeting of these criteria under the Natural Gas Act.

The Tennessee 50–50 Method

As noted above, the frank and revealing testimony by Staff witness Drescher indicates clearly how inherently difficult it is to attempt to calculate or measure the dollar level of adjustment which would be appropriate to reflect the unfavorable characteristics of the New England Zone. Under these circumstances, it seems particularly desirable that this problem should be resolved in a way which gives some recognition to the historical allocation pattern which has been in effect on the Tennessee system since the Docket G–1741 zoning settlement of 1952. It is accordingly concluded that the Tennessee allocation method, under which 50 percent of transmission costs are allocated on a mileage basis and 50 percent on the basis of historical revenue factors, represents the most satisfactory proposal for the resolution of this problem. It is further concluded that the Tennessee method effectively accomplishes the objective outlined above—*i.e.*, the adoption of an Mcf-mile approach, adjusted in some reasonable and limited manner to account for the unfavorable New England Zone characteristics, but exercising some reasonable restraint as to the burden to be imposed upon that zone.

In the first place, to the extent that 50 percent of the transmission costs under the Tennessee method are allocated under the historical G–5259 revenue pattern, which itself reflected a compromise split between the results flowing from the application of the straight Mcf-mile method and those under the zone-by-zone approach, the effect is to impose some penalty upon the New England Zone, as a rough factor giving recognition to the unfavorable characteristics referred to above. The penalty, however, is not as serious as that resulting under the Staff method. At the same time, it is of interest to note that the Tennessee method similarly allocates a lower cost than the Staff method to the Eastern Zone, which is the main source of supply for Columbia and Consolidated, advocates of the zone-gate method in this proceeding.

In addition, as noted above, there is something to be said in favor of the recognition which the Tennessee method gives to some extent, to the historical allocation pattern which has now been in effect on the Tennessee system since 1952. It is of interest to note, in this connection, that in the *Northern Natural* zoning case, Op. No. 281, the Commission in finally setting the zone *rates* made some modification from the precise result obtained by application of the Mcf-

mile method, in the direction of decreasing the amount of the zone rate differentials thus derived. The Commission exercised its discretion to make this modification in the *Northern Natural* case because of its desire to soften the impact of the departure from the historical rate patterns on that system. The dissenting opinion in that case stated:

> We recognize, furthermore, that, when departures from historical rate patterns are to be made, some softening of the impact may be appropriate.

Similarly, in the instant proceeding it appears that rates have now been collected over the entire Tennessee system for a period of eight years on the basis of the historical allocation pattern arrived at in the G–1741 zoning settlement of 1952; that Tennessee has expanded substantially, and its customers have grown and made large investments under such historic zone rate differentials, which have not varied significantly over the years. Under these circumstances, it is concluded that it makes sense to reflect that historical allocation pattern to some extent in the zone allocation levels which are now to be fixed for the future for the Tennessee system. It is important to bear in mind here that the Staff adjustments, described above, do *not* reflect or give weight to the historic rate *differentials*, or the historic *relationship* of zone rates on the Tennessee system. They simply charge to the New England and New York Zones the G–5259 revenue levels for those two zones. Under the Tennessee method, however, 50% of the transmission costs *are* allocated in such a way as to reflect and give weight to the historic rate *differentials* on the *entire* Tennessee system, as they existed under the G–5259 revenues.

The Tennessee allocation method will accordingly be adopted here, subject to certain modifications which will be dealt with at a later point.

At this point it will be of interest to set forth a tabulation showing the comparative costs allocated to each zone under each of the allocation methods presented in this proceeding. This will indicate at a glance the practical effect of the adoption of the Tennessee allocation method, as distinguished from the other suggested methods."[44]

[44] The data shown on this table is summarized from Tennessee Exh. 139. Costs allocated to each zone are based on Staff's total system cost of service, Exh. 92—pursuant to the Commission's order of May 6, 1959 requiring that all allocation studies should be presented, for the purpose of convenience, "in terms of the proposed cost of service heretofore served by the Staff upon the parties". It should be borne in mind, however, that non-zoning cost-of-service issues will not be determined until a later stage of the instant G–11980 proceeding, and accordingly no conclusions are here being drawn as to the merits of the Staff's total system cost of service.

	Columbia Interveners (Exh. 109)	Consolidated Interveners (Exh. 117)	New England Interveners (Exh. 101)	Staff (Exh. 97)	Tennessee (Exh. 116)[1]
Sales:					
Southern Zone 1	$23,014,151	$22,131,880	$23,182,434	$23,142,175	$22,683,241
Central Zone 2	17,067,755	16,891,574	17,533,137	17,361,176	17,461,793
Eastern Zone 3	62,037,218	63,233,762	67,976,129	67,029,625	66,460,794
Northern Zone 4	32,534,546	32,963,603	33,572,626	32,530,478	33,503,195
N.Y. Zone 5	26,613,333	27,937,077	26,394,342	26,367,457	27,014,352
New England Zone 6	23,852,427	21,607,221	16,823,086	19,354,014	18,614,416
	185,119,430	184,765,117	185,481,754	185,784,925	185,737,791
Transportation:					
T-1	3,876,348	3,822,104	3,792,768	3,685,135	3,746,650
T-2	3,628,593	3,137,039	2,446,582	2,463,548	2,461,549
T-3	2,024,157	2,079,547	2,420,492	2,352,019	2,324,373
T-4	5,240,534	5,337,174	5,745,624	5,601,519	5,710,476
	14,769,632	14,375,864	14,405,466	14,102,221	14,243,048
Total jurisdictional	199,889,062	199,140,981	199,887,220	199,887,146	199,980,839
Nonjurisdictional and other	8,296,879	9,044,960	8,298,721	8,298,795	8,205,102
Total	208,185,941	208,185,941	208,185,941	208,185,941	208,185,941

[1] As will be developed at a later point, four modifications are being made in this decision to the Tennessee Exh. 116 cost allocation study—(a) the use of the staff's 3-day peak, instead of Tennessee's annual Mcf demands, in connection with the Mcf-mile allocation; (b) the rejection of the Tennessee proposal to switch from a 50% to a 75% factor in the design of its rate for the Seller's Option (SO) service; (c) the treatment of PSG service on a simple, crediting-out basis, as recommended in the Tennessee briefs, instead of under the method employed in Tennessee Exh. 116; and (d) the allocation of costs to the SS-5 service under the Exh. 65 segregation of facilities method, as recommended in the Tennessee briefs, instead of under the Exh. 116 method. These changes are not reflected in the allocated costs shown for the Tennessee method in the above tabulation, since those figures are obtained from Tennessee Exh. 116. Appendix Table B, set forth at the end of this decision, represents a recomputation of Tennessee's Exh. 116 in such a way as to reflect these changes or modifications, and it indicates the results which flow from these adjustments to the Tennessee allocation. It is to be borne in mind, however, that the computation with respect to the SS-5 service on Appendix Table B of necessity represents merely a short-hand, rough treatment, as explained in a footnote to the Appendix Table. Appendix Table C repeats the above tabulation of comparative allocated costs, substituting in the last column the adjusted costs allocated to each zone under the Tennessee method as here modified. These adjusted costs are taken from Appendix Table B.

We now turn to a discussion of certain subsidiary issues raised in this proceeding.

Transportation Service

One of the subsidiary issues raised here involves the allocation of transmission costs to transportation service. In rendering this service, under its Rate Schedules T-1, T-2, T-3, and T-4, Tennessee acts merely as a carrier, receiving gas owned by the customer at a specified location, and transporting it for the customer's account to a specified delivery point. As already noted above, in applying the Mcf mile allocation method to gas *sales*, Tennessee (as well as the Staff and the New England intervenors) determined and used the distance from the *average point of receipt* of its system gas supply to each point of delivery. However, with respect to *transportation gas* Tennessee (as well as the Staff and the New England intervenors) computed the mileage from the *actual point at which the gas was received* for the account of the particular transportation customer.

Columbia contends that this was improper; that it in effect creates four new zones for transportation deliveries, and disregards the fact that the transportation gas is commingled in the Tennessee pipeline and becomes a part of Tennessee's common gas supply. Columbia further argues that so long as zones exist on a pipeline, *all firm deliveries* within each zone should be treated alike in the allocation of transmission costs; that, accordingly, if deliveries of transportation gas take place in a particular zone, such deliveries should take that same zone rate (less the production component). This is, in fact, the manner in which transportation service is handled under Columbia's own zone-gate method.

Although it is, of course, true that gas picked up by Tennessee for delivery under a Transportation Service schedule may be physically commingled with gas owned by Tennessee itself, the Columbia argument overlooks the fact that the transportation service rendered by Tennessee, for which it is to be compensated, consists of the receipt of the customer's gas at a specified point and the delivery of the same volume of gas to the customer at a designated delivery point a certain number of miles away. In one way or another, whether directly or by displacement, Tennessee is required to haul the volume of gas contracted for, the relevant number of miles.

The unsoundness of the Columbia position becomes immediately evident if we consider a currently existing situation in which gas is transported for Tennessee by Transcontinental Gas Pipe Line Corporation for delivery to Public Service Electric and Gas Company, a Tennessee customer. Such gas is received by Transcontinental in New Jersey, and after a relatively short haul is redelivered in the same state. Under the Columbia theory, if the situation were reversed and Tennessee were in fact rendering such transportation service for Transcontinental, Tennessee would be required to charge for such transportation service the high New York Zone rate (less the production component), which would thus be based not upon the actual miles of haul under the transportation service contract, but rather upon mileage measured all the way from the average point of receipt of Tennessee's system gas supply to the New York Zone delivery points.

Such a position seems quite unreasonable, and it is here rejected.

The Iroquois Zone Boundary Complaint

Intervener, Iroquois Gas Corporation which takes most of its CD (contract demand) deliveries from Tennessee south of Buffalo, New York, at a point approximately 68 miles from the Pennsylvania-New York state line, complains that the use of the Pennsylvania-New York state boundary as a dividing line between the Northern and New York rate zones is unfair and discriminatory. Because of its location in the New York Zone, Iroquois is required to pay the New York Zone rate, involving a differential of 5.9¢ per Mcf above the current effective Tennessee rates for the Northern Zone. Iroquois complains that other New York Zone customers, located 300 miles downstream from Iroquois, are eligible for the same New York Zone rate, and that customers over 200 miles east of Iroquois, who happen to have their connections with Tennessee in the state of Pennsylvania, are eligible to buy gas at the lower Northern Zone rates.

Iroquois contends that the fairness of zone boundaries is as much a part of the zoning issue as the allocation of cost of service between accepted zones; that a rate differential predicated on an inequitable zone boundary is *ipso facto* discriminatory; that "a fair zone boundary would be located no farther west than a point immediately to the east of the junction of Tennessee's line with its Niagara spur, and might well be located as far east as Tennessee's proposed Station 237". The effect of such a zone boundary change, of course, would be to remove Iroquois from the New York Zone, and to make the lower Northern Zone rates applicable to the Iroquois purchases from Tennessee.

This Iroquois contention that it should pay the Northern Zone rate because it is near the Northern Zone, ignores the existence of zone boundaries and amounts to a claim of preferential treatment for a single customer within the New York Zone. The entire argument, of course, is basically an attack upon the use of a zoning system *per se*. Under the Mcf-mile method in general (and under any zoning system at all) one of the inherent characteristics is the necessity for the use of some averaging process under which costs are averaged for all customers in a given classification within a given zone. This averaging proc-

ess could only be avoided by assessing each individual point of sale and delivery with the total of the various cost components incurred in the rendering of service to that point. However, the Commission has held in the *Northern Natural* case, Op. No. 281, that

> * * * any attempt to arrive at such perfection would be not only delusory, but also impracticable and infeasible from both the management and regulatory point of view. (14 FPC 24–25)

Accordingly, so long as a method is employed involving the establishment of service zones, with rate differentials for each zone, there are bound to be situations of the very type emphasized by Iroquois. The New England interveners have realistically characterized this situation as follows:

> Obviously zone boundaries are merely lines, arbitrarily drawn for the sake of convenience, which separate an otherwise integrated pipeline operation into segments for purposes of rate design and administration. Although certain inequities might be eliminated by a realignment of Tennessee's present zone boundaries, no practical way has yet been devised to avoid completely the problems inherent in the zone boundary itself. A customer just a short distance downstream from a zone boundary can never be convinced that the boundary is properly located. * * * The Mcf-mile method cannot eliminate this inherent zone boundary problem but it can, and does, reduce the resulting inequities to a minimum by assuring as equitable and uniform treatment as is possible to all customers regardless of geographical location. (initial brief, p. 11)

It is noted that in spite of Iroquois' above complaint with respect to the existing zone boundaries, it did not in this proceeding present any proposal for a different set of zone boundaries. The fact is that none of the parties presented any such proposal, and the entire case was tried on the assumption that the only issue presented was as to the method to be adopted for the allocation of costs between the *existing* zones on the Tennessee system. This was made clear in the following colloquy at the hearing:

> PRESIDING EXAMINER: * * * I think it would be correct to state that not a single one of the parties in this proceeding has presented any proposal or recommendation whatsoever that the existing zone boundaries on the Tennessee system should be changed. I see Mr. Holland rising.
>
> Are you questioning the accuracy of my statement?
>
> Mr. HOLLAND:[45] No, not in this sense, Mr. Examiner. Our witness has not proposed change, but he has testimony in the record to indicate that the existing boundary between the Northern and New York Zones is inequitable.
>
> PRESIDING EXAMINER: But he does not suggest any change?
>
> Mr. HOLLAND: He is not specifically proposing a change. We do not have the burden of proof in this case, Tennessee does. And I think that any intervener is entitled to object to a particular zone boundary as being inequitable without having to suggest a specific alternative. I am sure that Mr. Nichols would be willing to do so, but I don't concede that that is our burden.
>
> PRESIDING EXAMINER: I don't want to get into a discussion here about burden of proof, but I don't think any of the parties, including Iroquois, expect the Examiner and the Commission, after reading some testimony

[45] Counsel for Iroquois.

suggesting that a certain zone boundary is inequitable, and the testimony which stops there, I don't think you expect the Examiner and the Commission to work out some new zone boundaries on the basis of a record which contains no evidence and no assistance for the Examiner and the Commission in making an allocation based on such new zone boundaries. So I won't have any difficulty with that, Mr. Holland.

But I go back to my previous statement, that none of the parties here has recommended any change in the existing zone boundaries. I am not interested in discussing why they have not done so. I think that one of the explanations is that it seems to have been generally assumed that the purpose of this proceeding was to determine the method under which Tennessee's costs should be allocated between the existing zones on the Tennessee system.

Now, if one of the parties had come in here and made a major presentation suggesting that the existing zone setup is wrong, and that it is not enough to talk about how we are going to allocate the costs between the existing zones, but we really ought to make a major restudy here of the whole problem of the existing zone boundaries on the Tennessee system, I am not suggesting that I would have concluded that it would be improper to go into that in this proceeding. But that is not the posture of this proceeding. (57:7516–18)

Iroquois contends that the testimony of its witness showed that "as a matter of economic history and of current gas usage that area in and around Buffalo which is served by Iroquois belongs with such other metropolitan districts along the northern fringe of the Appalachian fields as Cleveland, Pittsburgh and Erie." On the basis of this meager testimony, plus a vague reference to the general mass of data in the entire record with regard to "mileage, the location of spurs, customer connections and compressor stations and the volume of gas taken at each connection (Ex. 90, tables and map)",[46] plus a reference to "the economic history of the Buffalo region" given by its witness, Iroquois now contends that the existing zone boundary between the Northern and New York zones should be moved to a different point, as described above. In making this proposal, Iroquois expresses no view as to whether fairness would require a change in any of the other existing zone boundaries, taking the position that the burden of resolving any such broader problems does not rest upon itself.

It is concluded that it would not be fair or reasonable, where the existing zone boundaries have been so long established on the Tennessee system, to give serious consideration to such a proposal for a mere fragmented change in one of the zone boundaries. This is particularly true under the current circumstances where the problem has been here presented in such a superficial way, without directing any attention to the impact or significance of such a fragmentary change in relation to other operations on the Tennessee system, or in relation to the entire problem of allocating Tennessee's system-wide costs between all zones on its system. It is concluded that if any serious attention is to be focused on the matter of whether the existing zone boundaries on the Tennessee system are unreasonable or inequitable and should therefore be changed, such an inquiry will have to be made on the basis of a much more serious and comprehensive study of the broad problem than that provided by Iroquois in the instant proceeding.

[46] None of this data was presented in relation to or with a view to considering any possible change in the existing Tennessee zone boundaries.

Selection of Basis for Allocating Demand Costs—Three-Day Peak v. Billing Demands

This issue arises in connection with the allocation of demand costs between zones under both the Mcf-mile method and the zone-gate method. Under the Mcf-mile method, the allocation ratios for each zone are constructed on the basis of mileage to delivery points within the zone, times the demand volumes delivered therein. The question presented here is whether such demand volumes should be measured on the basis of deliveries during a three-day peak period, or on the basis of average billing demands. Similarly under the zone-gate method, in determining how demand costs "incurred" in a given zone should be distributed between that zone and the downstream zones, the allocation is made on the basis of the relative demand volumes delivered in each of such zones. Accordingly, the question again arises as to how such demand volumes should be measured.

Essentially, two bases for allocating demand costs have been proposed in this proceeding:

(1) The Staff and Consolidated advocate the use of the average of a 3-day peak period, although they differ as to the particular 3-day peak period to be employed. The Staff uses the average of the 3-day system sustained peak period for the winter of 1956–57, which occurred on January 16, 17, and 18, 1957—outside of the test period. (47:5376, 5381; Exh. 90, Sch. 1). Consolidated, on the other hand, uses the average of a 3-day system sustained peak which occurred on December 24, 25, and 26, 1956, inside the test period. (47:4978; Exh. 78, Sec. IV—15, *et seq.*). Although Columbia advocates the use of billing demands, rather than peak days, it contends that, in the event a 3-day peak should be adopted in this proceeding, "the January 16–18 peak should be used because it more accurately reflects the market requirements for which capacity was provided during the test year." (Initial brief, p. 93).

(2) Tennessee, the New England intervenors and Columbia advocate the use of test year average monthly billing demands. (47:5240, 5321–2; 68:8949). In the case of general service customers, the monthly billing demand represents the maximum delivery to such customers on any one day during the particular month and the previous eleven months. In the case of contract demand customers, the monthly billing demand represents Tennessee's contract obligation to such customer. (Item C). For service under flat rate schedules, a billing demand was imputed based upon the load factor inherent in such rate schedules.

Tennessee contends that the use of the average of the monthly billing demands is more realistic and appropriate for this purpose than employing the average of a 3-day peak period. It is contended that the billing demand method avoids incorrect results and distortions obtained by use of the 3-day peak period when a system is expanding during the test period. Tennessee contends, in this connection, that irrespective of which particular 3-day period is selected in this case, it produces incorrect results because during the test year Tennessee was expanding its system, with substantial facilities (authorized in Docket No. G–9448) being placed in service in the late fall of 1956. It is argued that although these facilities were actually in service for less than ¼ of the test period, the use of any 3-day peak occurring after such facilities were installed results in the allocation of annual demand costs as if those facilities had been in service for the entire period. It is further contended that the claimed distortion is particularly serious where the allocation is made on the basis of a peak period occurring outside the test period, immedi-

ately after the installation of substantial additional facilities. Tennessee witness Davis stated, in this connection, that it is inconsistent to compute a rate base for the test year on the basis of monthly averages of plant investment during the year, and to allocate demand costs on the basis of a 3-day peak period occurring at the end of the year or after the test period, when substantial additional facilities were installed. (68:8950–3). It is insisted that the use of billing demands, on the other hand, more properly reflects the growth of demands during the test year, and that this is accordingly consistent with the determination of the rate base which similarly reflects the growth of capacity during the year.

Although the Staff advocates the use of a 3-day peak method in this case, little attention is devoted to this particular issue in the Staff briefs. Its only discussion of the problem consists of six lines on page 32 of Staff's initial brief, as follows:

> Further, in respect of Tennessee's use of billing demands, the Staff would note that it is not aware of any rate case in recent years where the Commission has determined demand responsibility on a basis other than actual peak demands. In addition, the use of imputed demands for allocation of demand costs may in other instances effectuate a predetermination of the number of dollars to be allocated to a zone.[47]

The Staff position on this question was, however, developed in the testimony of its witness Blair. In explaining his reasons for employing the average of the 3-day system sustained peak period of January 16–18 1957, Blair testified:

> A. It was my belief that the peak selected for allocating demand cost should be the highest peak reached during the winter season at the end of the test year. When the test year is a calendar year such as is the situation in this present case, Docket G–11980, in which the test year is the calendar year 1956, I believe that the proper peak for allocating the demand costs for this test year is the highest peak attained on the transmission system during the winter at the end of that year, which happened on those three days that you mentioned in January of 1957. (49:5665–66).

Blair explained his rationale for using the highest peak in the winter season as follows:

> But I would like to point out that one of the reasons for using the highest peak in the winter season is to avoid giving customers who have poor load factors favorable treatment to which they are not entitled—I mean, if a lower peak is selected for allocating demand cost such as a peak during the month of December, which is generally a warmer month than January or February, the full peak of the low load factor customers taking large quantities of gas during cold weather as against the relatively small volumes which they take during the year on an average basis would not be properly reflected.
>
> If a warm period is selected for the peak instead of the real, genuine highest peak of the winter, the low load factor customers are not assessed a proper share of the demand costs. (49:5668–9).

In applying his 3-day peak method, Staff witness Blair made certain adjustments to the deliveries actually experienced during the peak period in order to meet the following objectives:

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[47] This latter reference is to Tennessee's use of an imputed billing demand for sales made under the flat rate schedules.

> * * * to eliminate any sales during the three-day peak in January which were caused or generated by additional quantities which became effective in service agreements after the end of 1956.
>
> I also attempted to adjust the 3-day peak deliveries for any emergency conditions or obvious abnormalties which occurred during the 3-day period. (49:5657).

Consistent with this standard, Blair made a number of downward adjustments to the January 16–18 3-day peak delivery figures in Sched. No. 4 of his Exhibit 90 (explained in Sheets 11–18 of Sched. 4). In addition, for similar reasons, Staff Exhibit 97–A made two further adjustments—the Niagara transportation service adjustment and the Northern Zone Rate Sched. PSG–4 adjustment, which will be referred to shortly and which are discussed in detail at pp. 25–27 of Staff's initial brief. The basic criteria which governed the Staff in making all of these adjustments were described by Blair as follows:

> * * * to bring the allocation of demand cost and the allocation of commodity cost into reasonable relationship one to another, and closer to the relationship which would exist under more normal conditions. (49:5715).
>
> * * * * * * *
>
> * * * since the cost which we were developing was to be used as a basis for designing rates for use in the future, it appeared that the costs which we developed should be adjusted to reflect something reasonably close to expected normal operations in the future. (49:5713).
>
> * * * * * * *
>
> PRESIDING EXAMINER: In other words, what you are reaching for is what you would regard as a more representative relationship, more representative of what would pertain for the future as between peak volume and annual volume?
>
> The WITNESS: That is correct. We always have these adjustments which need to be made in rate cases, nearly always we have them. (49:5714).

As to the technique employed to accomplish this objective, Blair explained:

> * * * we have a choice of two methods of making the adjustment. One would be to normalize the sales during the test year, and the other one is to adjust downward the peak which is used for allocating demand cost. And it appears to me that the most practical method would be to adjust downward the peak used for allocating demand costs. (49:5712).

The Niagara transportation service adjustment, referred to above (made in Exhibit 97–A, Sched. No. 5, Sheet 2) involved a downward adjustment to the peak demand responsibilities for the T–2 transportation service to Niagara. Staff Exhibit 90 (Sched. 1, Column 5, Line 12) showed an actual 3-day peak of 68,537 Mcf for Rate Schedule T–2, Niagara Gas Transmission, Ltd. In Exhibit 97–A, Sched. 5, this actual peak figure was reduced to 40,000 Mcf. Blair explained that this Niagara transportation service was in a period of development during the test year, and that this represented an abnormal situation which would possibly not exist in the future; that accordingly the use of the actual, high 3-day peak for the January, 1957, peak period would have resulted in an excessive allocation of demand cost to that service, as compared to the allocation of commodity costs to the same service; that a downward adjustment to peak period deliveries was therefore made in order to bring the allocation of demand costs into a more reasonable relationship with the allocation of commodity costs, in order "to reflect operations which

would be more near normal or what might be expected to be normal in the future." (49:5705). He regarded this adjustment as similiar to the adjustment made in the situations involving a post-test year increase in the maximum daily quantity, resulting from the execution of a new service agreement.

It is thus clear that the Staff applied the 3-day peak method in a liberal and flexible manner, making a genuine effort to avoid the introduction or reflection of any distorted or abnormal situations. Tennessee, however, contends that the Staff adjustments do not go far enough, and that distortions can only be satisfactorily avoided by the use of average billing demands.

It is concluded that the Tennessee position on this issue has been completely answered and clearly disposed of by the Commission in its *El Paso* decision, Op. No. 326 and 326-A, *supra*. One of the controverted issues dealt with by the Commission in the *El Paso* rate proceeding was the selection of the peak period to be used for the allocation of demand costs between jurisdictional and non-jurisdictional sales. Although the test year employed in that case was the calendar year 1955, the Commission made its allocation on the basis of a Feb. 8–10, 1956, peak period, stating:

> In allocating demand costs, the presiding examiner approved El Paso's using the average of deliveries on February 1, 2, and 3, 1956, for the Texas, New Mexico, and Arizona customers, and the month's highest contract billing in the test period December 1955, for the California customers, rather than the coincident maximum use of El Paso's facilities measured by the actual peak deliveries on its system on February 8, 9, and 10, 1956, employed by the Staff. The use of the February 1, 2, and 3 peak is justified, in the Presiding Examiner's view, by the fact that sales to utility customers in Texas, New Mexico, and Arizona were substantially greater in this period, as well as by the fact that the higher priority utility sales were greater relative to industrial sales in the February 1, 2, and 3 period than in the February 8, 9, and 10 period. The presiding examiner said that he selected the December 1955, period for the Southern California customers because he thought deliveries to these companies were at a nearly 100% load factor, and the evidence would not support the use of the February peak-days, which produced a load factor for them of less than 100%.
>
> Staff counsel excepted to the presiding examiner's selection of peak days in allocating demand costs, *contending that the period to be utilized should include the actual system peak deliveries to all customers during the 1955–1956 heating season*, on February 8, 9, and 10, 1956, and averaging 2,167,188 Mcf; as contrasted to the presiding examiner's peak period, which represented average deliveries of only 2,022,751 Mcf on the system. Staff counsel argues that failure to utilize actual deliveries and allocate on the basis of maximum system demands permits some customers to escape without payment of demand costs properly allocable to them. Staff counsel contends further that the Commission rejected a similar dilution of maximum use for purposes of allocation in the Northern Natural case, 11 F.P.C. 123, 136–137, and that employment of selective peak periods violates fundamental allocation procedures and would unduly favor the California Companies. Southern Union Gas Company and the New Mexico Commission made similar contentions. We cannot adopt the presiding examiner's view on this point. To select a peak-day for one group of customers and another peak day for another group of customers is arbitrarily artificial and perhaps discriminatory. *To fairly allocate costs among various groups of customers taking at various load factors and under various conditions, it is*

essential to choose a maximum coincidental peak and apply it to all the customers. (22 FPC 260, at 279–280). [Emphasis supplied.]

Subsequently, in its order denying rehearing, Op. No. 326–A, the Commission disposed of this problem in even stronger and more compelling language, as follows:

> As we stated in Opinion No. 326, we chose the February 8–10, 1956 period because it represented the highest demand on El Paso's entire system for the 1955–1956 heating season. * * * What is significant as an equitable basis for allocating demand costs is the amount of gas each customer takes when the whole system is making maximum deliveries. This will determine the responsibility most clearly for El Paso's installed facilities as they are represented by demand costs. *In our view it is also immaterial that increased deliveries during the February 8–10 period were the result of an order allowing revised tariff sheets and service agreements to take effect or that the peak may have reflected compressor station capacity put in service in December of 1955.* The customers were making use of El Paso's facilities in proportion to their actual takes of gas during the peak period.
>
> * * * * * * *
>
> * * * Since as we have previously indicated this case was tried on the basis of establishing rates *prospectively*, it was necessary to go beyond the test year to reach the system peak for the winter heating season so as to arrive at rates representative of actual conditions just as we went beyond the test year to take into account certain wage increases. (22 FPC 666.)

In the *El Paso* case, *supra*, in explaining its selection and use of a 3-day peak period beyond the end of the test year the Commission stressed the fact that the purpose of that proceeding was to establish rates *prospectively*. Similarly, in the instant Tennessee case the task before the Commission is to determine which method should be adopted to allocate costs between zones on the Tennessee system *for the future*, and this will determine the resultant rate differentials which will be prescribed for each of the Tennessee zones for the future. Accordingly, it seems clear that the criteria laid down by the Commission in the *El Paso* case are equally applicable here; that our allocation of demand costs in this proceeding should therefore reflect the relative demand requirements between the zones at the time when the whole Tennessee system is making maximum deliveries; that the period of maximum deliveries is the 3-day period representing the highest demand on the system for the winter heating season commencing in the test year; that the Staff's 3-day peak period of January 16–18, 1957, meets this requirement. It is of interest to note that Tennessee witness Rogers testified in this connection:

> A. The January three-day sustained peak is more representative of the entire winter season which was accomplished with the facilities that existed in the year 1956, or at the end of 1956.
>
> Q. Taking into account what you stated, that your peak is apt to occur in January rather than in December?
>
> A. Yes, sir. (24:3266)

Tennessee itself notes in its initial brief (p. 46) "that the Commission has on numerous occasions in the past adopted the use of a 3-day peak in allocating demand costs," and notes further that the Commission recently adopted a 3-day peak *outside the test year* for the allocation of demand costs on the El Paso system. However, Tennessee attempts to distinguish such other cases on two grounds: (1) that the major problem in those cases was the allocation of

demand costs between jurisdictional and non-jurisdictional sales and transportation; (2) that in almost all instances the issue involved was the selection of one peak period over another, rather than the issue here presented of a 3-day peak vs. average billing demands.

The fact that the other cases cited involved an allocation of demand costs between jurisdictional and non-jurisdictional sales, and not an allocation of costs between zones, is a distinction without a difference, and has no real relevance to the problem we are here considering. The fact is that the same arguments and considerations advanced by Tennessee against the use of a three-day peak period in the instant proceeding were equally applicable to the problem of allocating demand costs between jurisdictional and non-jurisdictional sales in the *El Paso* case, *supra*, and were there rejected for reasons which are equally persuasive here. Further, it is of particular interest to note that in the *Northern Natural* zoning case, Op. No. 281, where the Commission adopted the Mcf-mile method for the allocation of costs between zones, demand miles were derived by multiplying *peak-day* volumes times mileage, as proposed by the Staff. The Commission stated:

> Transmission demand miles were computed by multiplying the mileage thus obtained for each delivery point by the three-day system peak average sales at each such point. (14 FPC 28).

The second claimed distinction in the cited cases is equally irrelevant. If anything, the fact stressed by Tennessee that in almost all the cited cases the issue raised was not the adoption of a 3-day peak vs. average billing demands, but merely which particular peak period should be selected, would seem merely to reflect the understanding by the parties that the Commission, as a matter of principle, is committed to the use of the three-day peak method in the absence of compelling circumstances to the contrary.

The Commission's decision in the *Alabama-Tennessee Natural Gas Company* case, Op. No. 226 (11 FPC 75), cited by Tennessee as supporting its position, clearly represented just such an exceptional situation. The Commission there stated:

> Where we have found a demand-commodity allocation appropriate, demand costs have been allocated on the basis of usage of the capacity of the system as measured by various peak period deliveries from such system. In the present proceeding, however, the company's witness and the Commission's staff witness on cost allocation agree that peak day or sustained peak usage for the test period under consideration would not be a proper basis for allocation of demand costs; the reasons being the developmental nature of the company's operations and the large amount of excess capacity on its system. * * *
>
> In short, the problem of allocating costs on this system is different from that with which we are faced generally.
>
> * * * * * * *
>
> We find on the facts of this case, that it is not appropriate to allocate any of the costs on a peak period demand basis, because of the relative insignificance of the peak loads on the company's system at this time. (11 FPC 84).

Because of the special and exceptional circumstances there noted, the Commission proceeded to make the allocation on the basis of the usage of system facilities for the test period as measured by the sum of the day-to-day deliveries, characterized as a volumetric basis. (11 FPC 82). However, it is of equal

importance to note that, in so doing, the Commission rejected a billing demand method proposed by the company, stating:

> The "Billing demand units" method of allocation proposed by the company's witnesses is inherently defective. (11 FPC 85).

No such exceptional or abnormal situation as that described in the *Alabama-Tennessee* case exists with respect to the Tennessee system in the instant proceeding.

It may finally be noted that a special problem is raised by Columbia (Initial brief, p. 89) with reference to the application of the three-day peak method in the instant proceeding. This problem relates to the fact that the Staff, in computing capacity responsibility on the basis of its three-day peak of January 16–18, 1957, included and reflected deliveries of 31,692 Mcf per day which were made by Tennessee to United Fuel Gas Company (a Columbia subsidiary) during this peak period under the Seller's Option (SO) rate schedule. Columbia contends that Tennessee elected to make these particular SO deliveries during a peak period as a matter of its own convenience, because certain of its customers were not taking their full contract quantities during such days; that United Fuel had no choice in this matter, since deliveries under the SO rate schedule are at the option of the seller; that Tennessee actually did not provide capacity for making such SO deliveries on the peak day; that accordingly, in the event the three-day peak method should be adopted here, such interruptible SO deliveries should be excluded in the computation of the three-day peak.

It is concluded that the Columbia contention must be rejected in view of the basic principle laid down by the Commission in the *El Paso* case, *supra*, that:

> To fairly allocate costs among various groups of customers taking at various load factors and under various conditions, it is essential to choose a maximum coincidental peak *and apply it to all the customers*." (Op. No. 326; 22 FPC 280; emphasis supplied).
>
> * * * * * * *
>
> What is significant as an equitable basis for allocating demand costs is the amount of gas each customer takes when the whole system is making maximum deliveries. * * * The customers were making use of El Paso's facilities *in proportion to their actual takes* of gas during the peak period. (Op. No. 326–A; 22 FPC 666) [Emphasis supplied.]

In the instant Tennessee case, the controlling fact is that whatever SO gas was actually delivered to United Fuel by Tennessee during the peak period was, of course, delivered over capacity in being, and United Fuel made use of Tennessee facilities in proportion to its actual takes of gas from Tennessee during that period, including its takes of SO gas.

It may further be noted that the problem here raised by Columbia is, in any event, no longer particularly significant in view of the fact that United Fuel in May 1959 converted from SO gas to firm gas purchases and is therefore no longer purchasing SO gas from Tennessee.[45] The sole impact of this issue would therefore lie in determining the proper level to be fixed for the SO rates from the beginning of the refund period on July 14, 1957, until United Fuel discontinued its purchase of SO gas in May, 1959. Columbia made no effort to indicate how the three-day peak method would be here applied in the event its position should be adopted with respect to the peak period SO deliveries to United Fuel, nor did Columbia present any calculation or estimate as to what dollar difference would result from making such an adjustment with respect to the limited period from July 14, 1957, until May, 1959. It may reasonably be assumed, however, that

[45] The facts in this connection will be developed in detail at a later point.

since the question here raised by Columbia relates only to a daily volume of 31,692 Mcf and is applicable only to a limited period, the dollar difference would in any event not be significant. Under these circumstances, the matter does not merit any more extended consideration in this decision.

Allocation of Costs to Storage Service (SS–5)

The problem here presented relates to the method to be adopted for the allocation of costs to the Tennessee Storage Service (SS–5), which is rendered solely in the New York Zone. Tennessee commenced rendering this service to Public Service Electric & Gas Company in November, 1956, under certificate authorization in Docket No. G–10804 (19 FPC 568). Subsequent to the test year, in Docket G–11107, Tennessee was authorized to render storage service to Brooklyn Union Gas Company and Long Island Lighting Company (21 FPC 70).

Although the total volumes (749,836 Mcf of annual deliveries) and revenue ($388,452) for the test year represent a relatively small proportion of the total delivery volumes and revenues for the New York Zone, a great deal of effort and time was devoted by the parties to this issue, both during the hearing and in the briefs. Despite all this effort, however, the parties have finally left the problem in a most unsatisfactory posture, as will be developed at length hereafter.

SS–5 gas is available only to a customer who also purchases gas from Tennessee under the CD–5 (Contract Demand) rate schedule (49:5751). The quantity of gas taken under the SS–5 rate schedule is specifically required to be cut-back from the customer's CD takes, since the Storage Service agreement provides that gas will be made available for storage by the reduction in Contract Demand deliveries to the Storage Service customer during the summer months. (Item C; 67: 8806–7) Tennessee is obligated to redeliver during the winter months an equivalent volume of gas at a specified maximum daily rate during a specified winter period, and the total annual volume which Tennessee is thus obligated to deliver under both the CD and SS–5 rate schedules cannot exceed the annual volume which Tennessee is obligated to deliver under the Contract Demand rate schedule. (68:8946) The SS–5 service accordingly simply represents the storing of a portion of the CD customer's gas in the summer for delivery during the following winter. Under the circumstances, since the SS–5 service is thus rendered from storage or by displacement because of the availability of storage (49:5750, 5758; 60:7858, 7882–3) it is not necessary for Tennessee to provide any additional pipeline capacity from the source of gas supply to the storage area in order to render this service. (67:8806–7) Tennessee does, however, provide additional pipeline capacity equal to the daily volume contracted for under the SS–5 rate schedule from the storage fields to the customer's delivery point, in order to deliver SS–5 volumes in the winter months in addition to the CD–5 volumes. (67:8807–8808)

Despite the facts with regard to the Storage Service, as outlined above, Columbia witness Nissel allocated costs to that service in exactly the same manner as to the CD–5 service—giving no consideration to the difference in the character of Storage Service as compared with Contract Demand service. He gave no recognition to the fact that no facilities are required for Storage Service from the source of gas supply to storage, or to the fact that the total annual volume which Tennessee is obligated to deliver under both the Contract Demand and SS–5 rate schedules cannot exceed the annual volume which Tennessee is obligated to deliver under the Contract Demand rate schedule alone. Similarly, Consolidated allocation witness Learned allocated cost to all deliveries in the New York Zone, including Storage Service, on the basis of the 3-day average peak and annual volumes without giving any consideration to the difference in

the character of storage service as compared with Contract Demand service—and his allocation thus, in effect, assigned the same cost to Storage Service as is assigned to Contract Demand service. (68:8944)

This approach, which assigns to Storage Service pipeline capacity from source of gas supply to the storage field, in addition to the capacity required for Contract Demand service, can only result in a duplicate charge for such capacity to the SS–5 customers. Staff witness Drescher correctly characterized this situation as follows:

> I am taking the position that the peaking capacity is complementary to the firm capacity purchased under a different rate schedule, and that in computing the dollars of cost which the customer is to pay you have to take into consideration what it is that he is being charged with in the way of costs under the firm rate as well as his obligation under the peaking capacity rate. You have to avoid any duplication of costs. He can't be charged twice for the same thing. (60:7943)

Along the same lines, New England intervenor witness Tippy testified:

> * * * a customer company which uses storage service in conjunction with its basic general or contract demand service has paid, in effect, through its demand charge, for the full capacity cost of facilities required for transmitting the storage service gas from the source to storage. This assumes, of course, that the contract demand customer backs off below his contract quantity in the summer months sufficiently to provide gas volumes at least equal to the storage service volumes he will require during the subsequent winter. Therefore, this general service or contract demand customer, with respect to the storage service gas, should be charged as to further capacity cost only for the further cost related to the transmitting of its storage gas from storage to the point of delivery beyond storage. The customer should not be charged twice either for the capacity or commodity cost of hauling the equivalent of the storage service gas from supply to storage. (62:8174–75)

It is true that both Consolidated and Columbia made adjustments calculated to reduce, to some extent, the costs which they thus assigned to the SS–5 service—but these adjustments do not cure the basic defect in their approach. Consolidated witness Chaney, in his recommended rate derivation method for the SS–5 service (68: 8943–44), assigned to that service per Mcf of contract demand, 65% of the demand cost assigned to Contract Demand service. (47: 5037–8; Exh. 107, p. 7c). As pointed out by Tennessee, the result may be reasonable but the method is fallacious. The 65% factor represents the ratio of storage service deliveries (18,815 Mcf) on the 3-day peak used by witness Learned (Dec. 24–26, 1956) to the monthly billing demand for that service (30,000 Mcf). However, it is merely by accident that on that particular 3-day peak the deliveries for this service were only 65% of the billing demand. Under normal circumstances, this accidental relationship would not have occurred. For example, the deliveries of storage service on the 3-day peak used by the Staff (Jan. 16–18, 1957) were 31,312 Mcf (Exh. 90, Sch. 4; 68:8944). If Chaney's method had been applied to the 1957 peak days used by the Staff, the resulting rate for SS–5 service would have been higher than that for Contract Demand service—obviously an incorrect result in view of the substantial difference in character of the two services.

Columbia witness Nissel's assignment of demand costs to SS–5 service was lower than that to Contract Demand service solely because of the credit given to the storage service under his capacity credit method—the capacity credit

arising from the charge made by Nissel to Seller's option (SO) deliveries in the New York Zone. This capacity credit, amounting to approximately $87,000,[49] resulted from the substantial volumes of SO gas delivered in the test period. (68:8946). The rate level for storage service under the Nissel method is thus made to depend upon the volume of Seller's Option sales—a result which seems clearly unsatisfactory.

Because of the controlling considerations outlined above with respect to the nature and characteristics of the Storage Service, Staff witness Drescher in his Exh. 97-A adjusted the Mcf-demand miles charged to the SS-5 service downward in such a way as to reflect only the miles of haul from storage to the delivery points at which the services are rendered, rather than the miles from the sources of system gas supply to those delivery points. (Sched. 5, Sheet 2). As a result of this adjustment, Drescher obtained an allocated cost of $423,544 for SS-5 service. (Sched. 2, Sheet 5).

While approving the Staff approach to this extent, both Tennessee and intervenor Brooklyn Union contend that two corrections are required with respect to the SS-5 storage service rate as determined by Staff witness Drescher. With respect to the first correction, it is contended that storage service was rendered only for the last two months of the test year; that despite this, witness Drescher in determining the demand cost assigned to Storage Service used the average of the 3-day peak occurring in January, 1957, in the total amount of 31,312 Mcf; that by using this 3-day peak, Drescher in effect assigned a demand cost to the SS-5 service which was equivalent to that which would be assigned if the service had been rendered for a full twelve month period. It is argued that if the cost is allocated to the service on a basis which represents a twelve month cost and revenues are only received from the service for the two months it was actually rndered during the test period, the deficiency in revenue is not due to any inadequacy in the rate, but instead is due to the inconsistency of using twelve months of cost as a basis of allocation and only the two months of actual revenue received by Tennessee. It is therefore suggested that the 3-day peak figure used by Drescher should be reduced to one-sixth of the actual 31,312 Mcf experience—which would result, according to Brooklyn Union's computation, in a reduction of approximately $185,709 in the demand cost of $217,021 which Drescher allocated to the SS-5 service. (Tennessee initial brief, p. 54; Brooklyn Union initial brief, pp. 18-19).

Some normalizing adjustment would appear to be required in this situation, on the basis of the same reasons and criteria which led Staff allocation witness Blair to make certain other adjustments to the January, 1957, 3-day peak delivery figures in his Exh. 90, Sched. 4—for example, the Niagara transportation service adjustment referred to at an earlier point in this decision. However, the indicated correction would not appear to be quite as severe as that suggested by Tennessee and Brooklyn Union. The objective here should be to insure that the relationship between actual SS-5 revenues for the test year 1956 and the peak-day volumes used for the allocation constitutes a normal, representative relationship which would be reasonably close to expected normal operations in the future. The proposed correction referred to above is a somewhat exaggerated one, because it assumes that in a normal year deliveries of SS-5 gas would take place over a full 12-month period. This assumption, however, ignores the facts with respect to Tennessee's delivery obligations under the SS-5 rate schedule. Under that schedule SS-5 gas is to be delivered by Tennessee during the 6-month period from November 1 of each year to May 1 of the following year, at a maximum daily rate of 30,000

[49] Brooklyn Union Gas Company initial brief, pp. 11-12.

Mcf, with a maximum delivery volume for the entire period of 2,700,000 Mcf.[50] This maximum delivery volume is defined in the contract as a quantity equal to ninety times the Daily Storage Quantity, which in turn is designated as the Winter Storage Quantity. Tennessee witness Davis testified:

> * * * the SS–5 rate provisions contemplate the delivery of the gas over a ninety day period. * * * (30:4094–5)[51]

It thus appears that the normal contract situation called for delivery over only a 6-month period, with a maximum delivery volume for such period of 2,700,000 Mcf. The total actual annual deliveries of SS–5 gas in the test year 1956, amounting to 749,836 Mcf, represented 27 percent of the contract maximum delivery volume of 2,700,000 Mcf. It would therefore appear, at the most, that the 3-day peak figure used by Staff witness Drescher should be reduced to a level no lower than 27 percent of the actual 31,312 Mcf experience, rather than to a level amounting to only one-sixth thereof, as proposed by Tennessee and Brooklyn Union.

In connection with their second suggested correction to the SS–5 storage service rate as determined by Staff witness Drescher, Tennessee and Brooklyn Union note that Drescher failed to assign to Storage Service any costs associated with the use of storage facilities, except for a relatively small portion (amounting to $5,124—60:7879) which was included in the transmission cost assigned to storage service. (68:8947) On this point, the Tennessee brief contents itself with the bare conclusion that—

> If the use of storage facilities were properly taken into account, this would tend to offset, although not completely, the over-allocation, mentioned above, resulting from the Staff's use of the 1957 peak period unadjusted. (initial brief, p. 54)

The Brooklyn Union brief carries the matter somewhat further, and concludes that if the use of storage facilities were properly taken into account this would require an upward adjustment to the Drescher SS–5 cost figure, amounting to approximately $92,000. (initial brief, p. 19) This figure was derived by multiplying the total 1956 volume of SS–5 gas, amounting to 749,411 Mcf, by a unit cost of service of top storage capacity at the level of 12.26¢ per Mcf. This 12.26¢ top storage cost figure was obtained from a statement showing estimated cost of service allocated to peaking service, filed by Tennessee on May 30, 1957 pursuant to an order issued by the Commission in the Tennessee certificate proceedings in Docket Nos. G–9331 and G–9448 (17 FPC 416). The said Tennessee cost statement was offered in evidence by Columbia as Exh. 66 in the instant proceeding, and was used by it as the basis for interrogation of Tennessee witness Davis.[52]

Columbia, however, contends that in the event the Staff approach is adopted for the allocation of costs to the SS–5 service, a much higher upward adjustment is required to the Drescher SS–5 cost figure in order to adequately reflect the use of storage facilities—*i.e.*, an adjustment amounting to $326,649. (Exh. 124, Sched. 1) In making this computation, Columbia witness Nissel commenced with a figure of $1,041,542 of underground storage facilities de-

[50] See Commission order of April 21, 1958 certificating SS–5 service in Docket G–10804, 19 FPC 568.

[51] Ninety days times the maximum daily rate of 30,000 Mcf produces the 2,700,000 Mcf maximum delivery volume figure for the entire delivery period.

[52] This Tennessee statement (Exh. 66) computed an estimated cost of storing gas in the Hebron Storage Field. The 12.26¢ per Mcf unit cost was arrived at by dividing a "total cost of service" of $2,451,320 by a top storage capacity of 20,000,000 Mcf. (Exh. 66, Sched. E)

mand cost, and $1,110,453 for underground storage facilities commodity costs—both verified by the Staff witnesses Blair and Drescher. (60:7873, 7876) He then proceeded to allocate the $1,041,542 demand cost figure between SS–5 service, PS–G service, and "other services" on the basis of the relative deliveries from underground storage to each such category of use during the 3-day January, 1957 peak period. The $1,110,453 commodity cost figure was allocated between these three categories of service on the basis of the relative annual volumes delivered to each from storage during the test year.

We are thus confronted with a wide disagreement between the parties as to the proper method to be adopted if the Drescher SS–5 cost figure is to be adjusted upward in order to more adequately reflect the use of storage facilities, and a wide disagreement as to the level of the required adjustment for this purpose. Neither the Tennessee nor the Brooklyn Union briefs comment upon the Columbia method, described above; Tennessee has not bothered to indicate what method it would employ; the Brooklyn Union brief merely embraces, in passing, the short-hand calculation referred to above, without discussion of any kind; and similarly the Columbia brief, with equal reticence, merely embraces, in passing, witness Nissel's shorthand calculation of Exh. 124, *supra*, without discussion of any kind. The Staff briefs contribute to this frustration by ignoring these problems completely. We are thus left without the benefit of the Staff's view as to whether either of the adjustments discussed above to the Drescher SS–5 cost figure are in fact required and, if so, how they should properly be computed.

In the context of this most unsatisfactory situation, we turn next to a consideration of Tennessee's current recommendation as to a method to be employed for the allocation of cost to the SS–5 service. In its initial brief (p. 55) Tennessee directs attention to the method of allocation used for Storage Service in the cost allocation which it submitted in September, 1956 in support of its proposed initial rate for this service, in connection with its application for authorization to render such service in Docket No. G–10804. The said cost allocation was set forth in a Supplement to Application, and an attached Exhibit X3, filed by Tennessee in that proceeding. In the course of the instant hearing, Columbia offered this Supplement and the attached cost allocation exhibit in evidence as Exh. 65, and used it as a basis for cross-examination of Tennessee witness Davis. Tennessee now contends that the method of allocation set forth in such Exh. 65 is a reasonable method for determining the portion of the total cost of service which Storage Service should bear, and recommends that this method be here approved. (Initial brief, p. 55; p. 65, proposed finding No. 15)

The Exh. 65 allocation method was, in fact, used by Tennessee for the SS–5 allocation in its original rate filing in the instant proceeding. (3:358; 30:4092) However, in its allocation exhibits presented in the instant proceeding (Exhs. 22, 51 and 116) Tennessee allocated SS–5 costs along with all other transmission costs, under its general 50% historical revenue pattern, 50% Mcf-mile method. (30:4100–3) The final phase of the Tennessee position on this problem occurred in its initial brief, where it informs us (footnote 57, p. 55):

> It is to be noted that in the preparation of Exhibits 22, 51 and 116, transmission costs were inadvertently allocated to Storage Service from source of gas supply to the storage field. On the other hand, insufficient costs related to storage facilities were allocated to this service in those exhibits.[53]

[53] These two "inadvertent errors" constitute the two corrections which Tennessee contends are now required with respect to the SS–5 storage service rate as determined by Staff witness Drescher.

> The effect on the over-all allocation of costs to zones is *de minimus* because the amount of Storage Service rendered in 1956 (749,000 Mcf) was comparatively insignificant. Nevertheless, for rate derivation purposes, the allocation in Exhibits 22, 51 and 116 is unsuitable for Storage Service. On the other hand, Exhibit 65 is a reasonable basis of allocation for this purpose.

Tennessee's Exh. 116 allocation to SS–5 service (based on the Staff's overall cost-of-service) produced a Storage Service cost figure of $399,107. (Exh. 116, col. 22, line 35) Revenues for SS–5 service at Tennessee's filed G–11980 rates, computed under the Exh. 65 allocation method, amounted to $388,452. (Exh. 116, col. 23, line 35)[54]

The Exh. 65 method was succinctly characterized at pages 1 and 2 of Exh. X3 to the G–10804 supplement, as follows:

> The rendition of this service requires the use of storage facilities and transmission facilities from the storage area to the point of delivery of gas. Accordingly, this cost of service determination is based upon those facilities which will be specifically used in rendering this service with no costs included with respect to other system facilities.
>
> * * * * * * *
>
> The proposed charges for this storage service are based upon a two-part rate composed of a demand charge and commodity charge. The cost allocation herein set forth is related solely to the demand charge in the proposed rate since the demand charge determines the additional revenue which Applicant will receive as consideration for rendering this proposed storage service. The commodity charge in the proposed rate schedule for gas put in storage is identical to and in lieu of the commodity charge contained in Rate Schedule CD–5 under which Public Service and Brooklyn Union each receive contract demand gas service. Thus, the collection of the 28¢ per MCF commodity charge under the storage service schedule upon delivery of gas substitutes for the same commodity charge which would otherwise have been collected under the CD–5 Rate Schedule had the gas been delivered and not put into storage.

At page 4 of the said Exh. X3, cost of service associated with the storage facilities was allocated between Storage Service and all other service on a volumetric basis, reflecting the ratio of top storage capacity required for Storage Service to total available top storage capacity. Tennessee explains:

> In other words, Tennessee's allocation of storage costs to this service is predicated on the concept that a storage field is the same as a warehouse with certain space available. Accordingly, the portion of the space required for the Storage Service is allocated to such service (Tr. 4094). (initial brief, p. 55)

Cost of service associated with natural gas transmission lines from the storage area to the point of delivery of gas was allocated to the proposed storage service 50 percent on the basis of the ratio of maximum daily volumes of storage service gas transported over such lines, to the maximum daily volumes of all other gas so transported; and 50 percent on the basis of the ratio of annual volumes of storage service gas so transported, to the annual volumes of all other gas. (Exh. X3, pp. 5 and 6)

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[54] The $388,452 figure, however, is based upon Tennessee's claimed over-all cost-of-service, and therefore reflects Tennessee's proposed 6.6% rate of return and 3.5% depreciation rate.

Tennessee notes initial brief, p. 55) that, since the cost allocation in Exh. 65 was prepared in connection with its certificate application in Docket G–10804, the allocation of transmission costs from storage to the delivery points for this special service was based on a segregation of the facilities used in rendering such service, and therefore, in this respect, departs from Tennessee's general zone application approach in this proceeding. However, Tennessee takes the posiition that "for the limited purpose of allocating costs *for this special type of service*" this constitutes a reasonable method. Brooklyn Union also supports the Exh. 65 method, stating that it—

> properly recognizes that the storage service is a segregated service and is in accordance with the physcial facts on which the service is rendered. It supports the form of the rate he[55] has determined and reflects the difference in the character of storage service as contrasted to contract demand service. (initial brief, p. 22)

The Columbia reply brief makes a strong attack upon the Tennessee proposal that the Exh. 65 method should be adopted in this proceeding. It is pointed out that Exh. 65 represented only a computation by Tennessee of *estimated* cost for SS–5 service, submitted in the G–10804 certificate proceeding; that it was prepared in 1956 based on estimated plant "to be as of April 1957"; that it reflected an average net underground storage plant (including three storage pools) of $35,265,000, or more than twice the test-year actual net investment (including only one storage pool) of 17 million dollars; that it estimated total top storage capacity to be 34,840,000 Mcf, whereas actual storage deliveries during the test year were only 6,955,143 Mcf; that Exh. 65 was accordingly unrelated to "actual" operating facts.

It must be remembered, however, that it is not our objective at this particular stage of the instant proceeding to calculate a dollar cost-of-service figure for the SS–5 service, or to design a rate for that service. The question presented here is merely whether the Exh. 65 *method* should be approved as an appropriate approach for the allocation of costs to the SS–5 service. At a later stage of the G–11980 proceeding, when attention is directed to completing the trial and determination of the dollar cost-of-service problems, it would become possible and appropriate to apply the Exh. 65 allocation *method* to the "actual operating facts" with respect to the existing storage facilities. A precise computation could then be made of the dollar costs to be assigned to the SS–5 service under that method, using the then-approved rate of return and depreciation rate for Tennessee, together with the then-approved commodity rate for the New York Zone.

Columbia further contends that the Exh. 65 method is defective in that it allocates underground storage facility costs on a purely volume basis, even though underground storage serves a demand function. There is, of course, no question that storage service does serve a demand function, in the sense that such gas is taken during periods of peak requirements, to supplement CD–5 gas. However, it is important to note here that the entire cost allocation study set forth in Exh. 65 is actually directed solely and exclusively toward developing the *demand charge* in the proposed SS–5 rate; and that all storage gas, whether under the SS–5 rate schedule or otherwise, is delivered during peak requirement periods. Under these circumstances, there does not appear to be any compelling reason for allocating storage facility costs between the different uses of such facilities on any other basis than the simple, straight volumetric basis. The use of the storage facilities is not analogous to the

[55] Tennessee witness Davis.

situation contemplated by the *Atlantic Seaboard* classification formula, and it does not present the same problem.

Columbia complains that, although Tennessee recognizes that the storage program is for the benefit of all customers in all zones, the effect of the Exh. 65 approach is to segregate the benefits of the low-cost underground storage facilities for the use of certain specific customers, and to deprive other customers of their pro rata benefit of such low-cost facilities. The gist of this argument is that SS–5 customers should not be allowed to benefit to such a degree from the low-cost storage operation, simply because of the geographical fact that they are located downstream from storage. This complaint, however, ignores the fact that under the Mcf-mile method, as adopted in this proceeding, the New York and New England Zones, because they are located at the far end of the Tennessee system, are required to pay a higher level of rates than any of the other zones. The New York and New England Zones are thus required to shoulder the *burden* of their greater distance from the common source of supply, and it is not contended by any of the parties that the cost impact of their unfavorable geographical situation in this respect should be shared by the other zones on the Tennessee system. Under the circumstances, it seems only reasonable and fair that the SS–5 customers in the New York Zone should similarly be allowed to enjoy the *benefits* flowing from the fact that they are geographically located downstream from the storage fields, and from the fact that they themselves made SS–5 gas available by cutting back on their takes from Tennessee during the off-peak months.

Columbia finally complains that the Exh. 65 method is completely at odds with the method which Tennessee advocated on the record in this proceeding, and that Tennessee witness Davis

> conveniently avoided a substantial amount of cross-examination by waiting until the record was closed to change his allocation method. (reply brief, page 24)

The fact is, however, that Columbia counsel interrogated witness Davis at length with regard to the Exh. 65 allocation method, at two different stages of the hearing (30: 4091–4109, and 68: 8973–78); and Davis at an early stage of the hearing expressed his approval of the Exh. 65 method, as follows:

> * * * in my opinion, that is a reasonable basis for determining the cost of service for that character of service. (30: 4105)

Curiously, the Staff's reply brief makes no comment whatsoever with respect to Tennessee's recommended Exh. 65 allocation method, but confines itself to a further attack upon Columbia's basic approach to the Storage Service allocation under its zone-gate, capacity-credit method. We are therefore left without the benefit of the Staff's view as to the merits of the Exh. 65 approach to this problem. The Consolidated briefs ignore the SS–5 issue completely.

Under all the circumstances set forth above, and bearing in mind that our only objective at this stage is to select the *method* to be adopted for the allocation of costs to the SS–5 service, it is concluded that the Exh. 65 method is a reasonable method for determining the portion of the total cost of service which Storage Service should bear, and that it constitutes the most satisfactory available method for the treatment of his problem.

Allocation of Costs to Peak Service (PSG)

The PSG service issue involves the same problems, the same conflicting positions, and is subject to the same analysis as the SS–5 service issue which has just been discussed at length—and a large portion of that discussion is equally applicable here.

The PSG issue is mainly a New England Zone problem, virtually all of the Peak Service gas having been sold in New England in the test year.[56] PSG service has been rendered by Tennessee on a year-to-year basis, under temporary certificates, since December, 1955, when the first such temporary authorization was issued by the Commission in Docket G–9331, for service terminating in April, 1956. Subsequently, in Docket G–9448 Tennessee obtained authority to render Peak Service on a temporary basis during the 1956–57 winter season terminating on April 30, 1957. (15 FPC 414) During both of these winter seasons PSG gas was sold at a flat rate of 70 cents per Mcf. In Docket G–11107 Tennessee sought to render Peak Service on a permanent basis commencing with the 1957–58 winter season under a permanent Peak Service rate schedule providing for a rate of 90 cents per Mcf, with a minimum bill provision of $12.00 per Mcf of maximum contract quantity.[57] While this proceeding was pending, the Commission granted Tennessee temporary authority by letter of October 14, 1957 to render such service at the 90 cents rate for the 1957–58 winter season, and again in Docket G–15826 granted further temporary authority to render Peak Service for the 1958–59 winter season.

Finally, in Docket G–11107 the Commission issued its order of January 28, 1959 denying Tennessee the requested *permanent* authority to render Peak Service. (21 FPC 70) However, although concluding that permanent service should not be authorized, the Commission held that the temporary authorizations were supported and justified, and authorized Tennessee to continue rendering Peak Service for the remainder of the 1958–59 winter season, stating:

> Thus in this very case, we cannot find the permanent certification of Tennessee's proposed Peak Service supportable, as discussed hereinafter. However, the temporary grant of such a service for the current heating season is clearly so. Although we cannot know on this record what additional facilities would be required to be built in the future to render permanent service, some would unquestionably be necessary. Nor can the extent of Tennessee's ultimate supply and other obligations for such a service be fixed with exactness on this record. And in the case of a permanent certificate, we would be required to consider such matters as the financibility of the necessary new facilities, the adequacy of gas supply, and the like. *In the case of the temporary short-term authorization, however, the evidence is clear that permission for it could be—and in Docket No. G–15826 was—properly granted without the necessity for constructing any new facilities whatever, or securing new volumes of gas supply. That service is being rendered by existing facilities and the volumes of gas in storage on Tennessee's system, which volumes were in excess of the needs for the winter. Thus, if these sales were not made, unused capacity would exist on the system, and gas would be kept in storage which could and should be sold for use by customers.* The severity of the current winter indicates how vitally necessary this service was and continues to be. Thus in granting the temporary authorization, we need not have recourse to the criteria applicable in deciding a request for a permanent certificate. And since no additional facilities or gas supply were necessary to grant the temporary

[56] A *de minimis* volume of PSG gas was also sold in the Northern Zone.

[57] In Docket G–11107 Tennessee submitted a cost allocation study in support of the 90 cent rate, identified as Exh. 339 in that proceeding. In the course of the instant hearing, Columbia offered this allocation study in evidence as Exh. 67, and used it as a basis for cross-examination of Tennessee witness Davis. This Exh. 67 allocation method, which was the basis for the derivation of the 90 cents per Mcf Peak Service rate, was similar (although with some exceptions) to the Exh. 65 allocation method advocated by Tennessee for the SS–5 allocation, which has been adopted here.

> authority, the grant of such authority, which otherwise serves important public interests, does not and cannot injure any of Tennessee's other customers or any other segment of the public. (21 FPC 76–7) [Emphasis supplied.]

The Commission then proceeded in its G–11107 order to direct that Tennessee

> * * * include as a part of its next major certificate application a firm proposal for the full incorporation of its underground storage facilities into the over-all operation of its pipeline system, and for the full utilization of its storage capabilities and the rendition of its services on a fixed and certain basis in a manner which will secure the maximum benefits of the storage equitably to all its customers. (21 FPC 81)

Pursuant to this directive, Tennessee subsequently filed a new certificate application in Docket G–18877, on July 1, 1959, relating to proposed utilization of its underground storage facilities. For reasons which need not be gone into here this proposal was not carried forward, and on May 2, 1960 Tennessee filed a new comprehensive proposal in Docket CP60–94. Subsequently, by letter dated August 25, 1960 and by an Amendment to Application in that docket, Tennessee has requested that processing of such application be delayed until it can re-evaluate its proposal in the light of the Commission's interim rate decision of August 9, 1960 in Docket G–19983. In the meantime, the practice has been continued of rendering peak service to the New England zone on a year-to-year basis. By order issued on Dec. 16, 1959 in Docket G–20096, the Commission authorized the delivery of peak service gas on a temporary basis for the period ending October 31, 1960, as "interim G–6 service" billed under the G–6 rate; and by order issued November 30, 1960 in Docket CP61–74, such interim service was again temporarily authorized for the period of one year from that date.

It thus appears that the Commission's G–11107 directive—*i.e.*, the development of a comprehensive new plan for the full utilization of the Tennessee underground storage facilities, designed, among other things, to replace the Peak Service for which permanent certification was denied in Docket G–11107—has still not been achieved and remains subject to still further proceedings. The question presented here is how best the Peak Service problem may be handled in the instant proceeding, in the light of the circumstances just outlined.

The PSG Rate Schedule provided

> that peaking service is available only to buyers under the General Service Rate Schedule for annual periods commencing on May 1st of each year, provided such buyers increase their General Service billing demands in effect on the preceding April 30th by 10 percent in the case of buyers whose General Service billing demand is less than 90 percent of Tennessee's maximum daily obligation to deliver, or 5 percent in the instances where the billing demand exceeds 90 percent. (21 FPC 80, footnote 14)

Tennessee states:

> Peak Service fulfilled three purposes. First, it provided the New England area with a much needed winter service which could compete with gas manufactured for peak shaving at a savings in cost. Secondly, because the ratchet provision for such service required customers to increase their billing demand for General Service by a specified percentage above that applicable in the previous year, the service provided a stimulus for load development. Finally, since the service was made available through existing facilities, it provided Tennessee with an additional source of revenues which otherwise would not have been available (Tr. 2582–4, 2599, 2600, 2614). (initial brief, p. 56)

The characteristics of the PSG service are in many ways similar to those of the SS–5 service, as described above. The PSG service was available only to customers also purchasing gas from Tennessee under the General Service (G) rate schedule, and PSG service was accordingly complementary to the firm capacity purchased under the G schedule. Because of space heating load characteristics, buyers under the G Rate Schedule released quantities of gas during the off-peak months, and this released gas (whether directly or by displacement) was made available to such customers under the PSG rate schedule as peaking capacity during the following winter. (49:5751) In addition, just as in the case of the SS–5 service, it is equally pertinent to note with respect to the PSG service that such sales were rendered either directly from storage or by displacement because of the existence of storage, that no main line capacity was installed by Tennessee for injection of gas into storage, and that Tennessee's main line facilities upstream from storage have an installed capacity equal only to the *average* daily requirements of the General Service customers.

Because of these controlling considerations, and in order to avoid charging PSG customers twice for the same capacity, Staff witness Drescher in his Exh. 97–A adjusted the Mcf-demand miles charged to the PSG service downward in such a way as to reflect only the miles of haul from storage to the delivery points at which the services were rendered, rather than the miles from the sources of system supply to those delivery points. (Sched. 5, Sheet 2) As a result of this adjustment, Drescher obtained an allocated cost of $728,454 for the PSG service in the New England Zone—translated into $1.15 per Mcf on a unit cost basis. (Exh. 97–A, Sched. 2, Sheet 6) Drescher testified that he had made a full allocation of costs to the PSG service; that although he recognized that the PSG service had continued for a number of years under annual rate schedules which had been cancelled at the end of each season, he had not treated it as a temporary service and did not use an incremental approach, because of the fact that PSG gas had already been made available for five or six years. (60:7915–16)

Despite the controlling considerations with regard to the PSG service, as outlined above, both Columbia and Consolidated allocated costs to that service under their general zone-gate approach, on the same basis as to any other on-peak service, making no distinction between Peak Service and Tennessee's regular firm services. This approach is subject to the same deficiencies which have already been pointed out with respect to application of the zone-gate approach to the SS–5 service, *supra*.[88] Under this method, Columbia obtained an allocated average cost of $3.45 per Mcf for Peak Service (Exh. 109, col. 9, line 32), as compared with the actual rate of 70¢ per Mcf which was in effect for PSG service in 1956, and the 90 cents rate which was in effect during the 1957–58 and 1958–59 winter seasons. During those last two winter seasons Peak Service sales amounted to a total of 4,394,564 Mcf. Under Columbia's formula, the cost allocated to the total Peak Service sales during that period would amount to $15,161,246, whereas the actual revenues collected were only $3,955,108. (68:8953–54)

Entirely apart from the basic deficiencies in the application of the zone-gate approach to the PSG service, it seems inherently unrealistic and unreasonable to allocate to a service which did not require the construction of additional

[88] Consolidated witness Chaney, in his rate derivation exhibit (Exh. 107, pp. 8a–8c), made an adjustment to this Peak Service allocation, by deducting the approximate amount of revenues actually received from Peak Service from the total cost of service allocated to the New England Zone, and then deriving a rate for that zone to recover the balance of the New England Zone cost. (68:8954–55) This adjustment, however, did not cure the basic error, since it merely had the effect of shifting a portion of the costs initially allocated to Peak Service to the General Service sales made in the same zone.

facilities, and which was rendered on a year-to-year basis under the circumstances outlined above, costs of the magnitude assigned to this service by Columbia witness Nissel. This seems particularly so in view of the fact that Peak Service gas replaced peak shaving gas and provided an additional source of revenues which otherwise might not have been available. (68:8954) It seems highly doubtful that Tennessee could ever have sold Peak Service at a rate of $3.45 per Mcf. (Item BB; 68:8912–14) The fact is that even with Peak Service available certain of Tennessee's customers were manufacturing some gas for peak shaving purposes. (19:2617)

With respect to the Staff approach, Tennessee here contends, as it did in the case of SS–5 service, that even if that method were here adopted for the Peak Service allocation, two corrections would be required: (1) because Staff's use of a peak period subsequent to the test year for allocating demand costs allegedly results in an over-allocation of demand costs to Peak Service; (2) because the Staff allocated only $10,643 of underground storage facilities cost to PSG service (60:7879). Tennessee, however, fails to indicate the magnitude of any such claimed adjustments, or how they should be computed.

In its own allocation exhibits in the instant proceeding, Tennessee handled the PSG allocation in the same way as the SS–5 service—*i.e.*, PSG costs were allocated along with all other transmission costs, under Tennessee's general 50% historical revenue pattern, 50% Mcf-mile method (Exh. 22, 51 and 116), producing a PSG cost figure of $449,551, based on the Staff's over-all cost-of-service. (Exh. 116, col. 22, line 43)

However, in its briefs filed at the end of this proceeding Tennessee now urges that the PSG problem be handled in quite a different manner—*i.e.*, by simply crediting the cost of service with the revenues received from the PSG service during the refund period, at the 90¢ per Mcf rate. In taking this position, Tennessee agrees that if Peak Service were a regular, long-term, special service for which facilities were constructed, there would be justification for treating it in the same manner as the other special long-term services in the allocation of costs. However, Tennessee contends that this is clearly not the case; that actually no additional facilities were constructed to render Peak Service, and there was no increase in costs to the other customers by virtue of the rendition of that service; that the incremental cost of such service was, in fact, substantially less than the revenues received; that Peak Service was rendered in competition with Peak Service gas, and if it had been eliminated there actually would have been no revenues at all to credit to the overall cost of service; that the service clearly would not have been purchased at any such rate as the cost allocated thereto by Columbia and Consolidated. Tennessee contends that under these circumstances it would be unfair and unreasonable to allocate costs to Peak Service in excess of the revenues actually received at the 90¢ rate, thus compelling Tennessee to suffer a monetary loss by virtue of its rendition of a service "that helped all and hurt none." In addition, Tennessee suggests that there is a substantial legal question as to whether costs can be allocated to this service in excess of revenues received, if the result is to deprive it of part of its cost of service. It contends that under the instant situation, where the Commission has denied permament authority to render Peak Service and where no additional capital investment was required to render the service, the standard practice should be to simply eliminate the revenues and the incremental cost of service, so as to normalize the test year operations. (initial brief, pp. 60–62)

In our attempts to resolve the PSG problem, we are confronted with a situation similar to that which was encountered with respect to the SS–5 service—in that despite the great effort and time devoted by the parties to the PSG issue, both during the hearing and in their briefs, the problem has nevertheless

been left in a most unsatisfactory posture. Among other things, the Staff reply brief makes no comment whatsoever upon the Tennessee proposal that the PSG problem should be disposed of by simply crediting the cost of service with the revenues received from such service during the refund period. We are thus left without the benefit of the Staff's view as to the merits of this approach to the PSG problem.

In determining the most appropriate method for the disposition of the PSG problem in this proceeding, the central fact to be borne in mind is that we are dealing here with a stop-gap situation—in the sense that the Commission in its G–11107 order of January, 1959 rejected Tennessee's request for permanent authorization for PSG service, and instead directed that Tennessee come in with

> a firm proposal for the full incorporation of its underground storage facilities into the over-all operation of its pipeline system, and for the full utilization of its storage capabilities and the rendition of its services on a fixed and certain basis in a manner which will secure the maximum benefits of the storage equitably to all its customers. (21 FPC 81)

The Commission went on to say, further:

> We think that this would possibly entail, with respect to Tennessee's Peak Service, the development of a storage service generally comparable to that Tennessee presently renders in New York.
>
> * * * * * * *
>
> Of course, the rates, terms and conditions of this service would have to be designed by Tennessee responsive to the New England market. While the rates should be fair and nondiscriminatory, they should be sufficiently low to assure the availability of the service in helping to meet the needs heretofore met by the Peak Service denied by this order. (21 FPC 81)

When Tennessee finally presents its plan for such a new service, pursuant to the above directive, and when that plan is passed upon by the Commission, it will become necessary and appropriate at that time to determine how the rate should be fixed for such service—and that determination will be made in the light of a detailed analysis and exploration of the cost characteristics of such proposed new service. It seems obvious that under these circumstances a determination of the costs to be allocated to the PSG service in the instant proceeding cannot be useful or meaningful with respect to Tennessee's future operations.

In its G–11107 decision the Commission, in referring to the 90¢ rate which it had previously authorized for Peak Service for the 1958–59 heating season on a temporary basis, stated:

> The inadequacies of this record are such as to preclude a finding that the rate for this service is insufficient to pay the costs properly allocable thereto, insofar as this question is material to the issuance of a temporary certificate. *Actually, this question is material primarily with respect to the issuance of the permanent, not the temporary authorization.* (21 FPC 77) [Emphasis supplied.]

The Commission further concluded:

> Since there has been no firm plan for utilization of Tennessee's storage, the difficulties of properly assigning the costs of the storage facilities to any particular service *are almost insuperable.* (21 FPC 81) [Emphasis supplied.]

In the light of the above conclusions, so strongly expressed by the Commission with respect to the Peak Service problem in its G–11107 decision, it is

difficult to believe that the Commission contemplated that this complex zoning case should be used as the vehicle for a full-scale resolution of the "almost insuperable" problem of determining what costs should properly be assigned to the PSG service—bearing in mind that it was rendered only as a year-to-year temporary service, and that it has now been replaced by still another temporary expedient, namely an "interim G–6 service" billed under the G–6 rate. Furthermore, if such an attempt *were* made in the instant proceeding, this in itself might well have the effect of circumscribing and limiting the ability of Tennessee to carry out the Commission's G–11107 directive that it come in with a proposed new plan for the fuller utilization of its underground storage facilities. For example, if the Columbia approach were here adopted for the PSG service, Tennessee could thereafter only make itself whole by substituting in place of the now-discontinued PSG service a new type of peaking service for the New England Zone, to which would be assigned the same high cost as that here advocated by Columbia for the PSG service. Such a result would be clearly irreconcilable with the objective laid down by the Commission in its G–11107 decision, that—

> * * * the rates, terms and conditions of this service would have to be designed by Tennessee responsive to the New England market. While the rates should be fair and nondiscriminatory, they should be sufficiently low to assure the availability of the service in helping to meet the needs heretofore met by the Peak Service denied by this order. (21 FPC 81)

Under all these circumstances, it is concluded that our objective here should be to dispose of the PSG problem in the simplest possible manner, on an *ad hoc* basis, and in such a way as to leave completely free for future determination the question of the rates to be established for any new service to the New England area, based on the fuller utilization of underground storage facilities. It is further concluded that this objective can best be accomplished by here adopting the Tennessee proposal—*i.e.*, by simply crediting the total cost of service with the revenues received from the PSG service during the refund period, at the 90¢ rate.

Allocation of Costs to Seller's Option (SO) Service

During the test year 1956, Seller's Option gas was delivered in the Eastern, Northern and New York Zones. Under the terms of the Seller's Option rate schedule, Tennessee has an obligation to deliver a fixed annual volume of gas, but has the option as to the time of delivery.

In its instant G–11980 rate filing, Tennessee has proposed an increase in the rate for its Seller's Option service. Previously, the rate for this service was the commodity rate in the zone, plus 50 percent of the CD demand charge converted to a commodity basis at 100 percent load factor. However, the new Seller's Option rate was designed to reflect *75 percent of* the CD demand charge converted to a commodity basis at 100 per cent load factor. Tennessee witness Davis testified that the purpose of this revision was

> to bring these rates in conformity with what I believe to be a sound rate structure for this class of service considering the related facility requirements. (3:357)

The Seller's Option service was inaugurated under Commission Opinion No. 193, issued May 3, 1950, under which Tennessee received initial authorization to deliver 20,000,000 Mcf of SO gas annually to United Fuel Gas Company. (9 FPC 70) On September 18, 1951 Tennessee commenced serving New York State Natural Gas Corporation in an annual amount of 8,000,000 Mcf of SO

gas, authorized at Docket No. G–1248; and on November 14, 1953 Tennessee commenced serving North Penn Gas Company in an annual amount of 5,390,000 Mcf, authorized at Docket G–2108. In justification of its proposed rate revision for the Seller's Option service, Tennessee lays great stress upon certain changes in the nature of its system operations since the SO service was first inaugurated in 1950, as follows:

> * * * At that time, Tennessee had no storage facilities and, therefore, designed its system to provide capacity approaching the *maximum daily* requirements of its General Service customers (Tr. 8813). Since such maximum daily requirements were substantially in excess of the average-day requirements of the General Service customers, Tennessee was able to rely upon this difference, as well as capacity not fully utilized by Contract Demand customers, to make the Seller's Option deliveries (Tr. 8813). With the advent of storage, however, Tennessee designed its system to provide capacity to meet the annual *average* day requirements of the General Service customers in the year in which they reached their maximum authorization, thereby eliminating capacity which was previously available for Seller's Option deliveries. At that time, however, Tennessee was experiencing reduced takes from certain of its Contract Demand customers, which reduction provided sufficient capacity to permit continued delivery of Seller's Option volumes. Subsequently, the load factor of the Contract Demand customers substantially increased, thereby virtually eliminating also that source of off-peak capacity which had been available for making Seller's Option deliveries (Tr. 8813–14, 2631–2) The situation became so serious in 1956 that Tennessee was unable to meet its Seller's Option obligations and, therefore requested and received permission from certain customers to be released as to a portion of its Seller's Option obligations (Tr. 8814–16) Indeed, the situation was so critical that Tennessee had to dip into base storage gas to meet the 1956 requirements of its customers (Tr. 220). (initial brief, pp. 47–48)

Tennessee then states:

> The determination to increase the charge for Seller's Option service, in the manner described above, was made because sufficient unused capacity was no longer available to meet Seller's Option obligations and, accordingly, capacity would have to be provided in order to continue to render the service (Tr. 4138–9) A study was made of the facility requirements, considering off-peak capacity that would be available, and it was determined that 156,092 Mcf of average-day capacity, equaling 88.3 per cent of the total Seller's Option contract commitments (176,696 Mcf), on an average-day basis, would have to be provided (Exh. 44). (initial brief, p. 48)

In further justification of its proposed new SO rate, Tennessee points to the fact that the rate for gas purchased under its Emergency rate schedule (E Schedules) and Interruptible Schedule (R Schedules) is the 100 per cent load factor rate; that service under these schedules is inferior to Seller's Option service inasmuch as unlike the SO schedule, there is no guaranteed annual quantity under the Emergency and Interruptible rate schedules; that accordingly the new rate is also justified on a comparative rate basis with such other schedules.

Tennessee finally concludes:

> It is abundantly clear that consideration of Tennessee's capacity situation in 1956 and the need to provide facilities for this service cannot be ignored in fixing the Seller's Option rate. The previous charge was based

on the fact that this service was met from off-peak capacity and provided an important source of valley gas disposal. These facts are no longer true, and, accordingly, the rate should be changed to conform to present day facts. (initial brief, pp. 51–52)

The Staff briefs make no reference to the Seller's Option problem. However, Staff Exh. 97–A utilizes and reflects the historical 50 percent factor for the SO service (Sched. 2, Sheets 3, 4 and 5). Staff witness Drescher supported this position on the following grounds: that during the test year 1956, no main line capacity was installed for SO gas; that normally SO gas is delivered off-peak; that the customers who purchase SO gas during off-peak months are themselves in an off-peak period, and accordingly would have to have storage in order to utilize SO gas; that SO gas is delivered at Tennessee's election, and the buyer must take or pay for it when tendered; that accordingly if in an abnormal year (such as in fact occurred in 1956) SO gas is tendered during peak periods, the buyer would have to have the capacity to physically take the gas at such a time, in order to avoid paying for something he could not take; that although Tennessee is obligated to deliver a fixed annual volume of SO gas, this is compensated for by a "rather high" minimum bill requirement under the SO rate, *i.e.*, the annual obligation times the SO rate itself. (50:5770–71)

Intervenor North Penn Gas Company (North Penn), which since 1953 has been receiving annually approximately 5,500,000 Mcf of Seller's Option gas from Tennessee in the Northern Zone, recognizes that Tennessee does have the contractual obligation to deliver an annual amount of SO gas and that accordingly *some* charge beyond a bare commodity rate should be assessed against such gas. However, North Penn contends that the historical 50 percent factor is entirely sufficient for this purpose, and that Seller's Option gas in any event should not bear demand costs anywhere near demand costs associated with CD service. North Penn calculates that if SO rates were computed for the Northern Zone, where its deliveries are received, on the basis of the proposed 75 percent factor, the result would be a spread of only 2.7¢ per Mcf between the rate for the firm CD service and the Seller's Option service; whereas, on the basis of the historical 50 percent factor, the spread would amount to 5.4¢ per Mcf. North Penn contends that the latter makes much more sense, in view of the peculiar characteristics of the SO service, as outlined above, as distinguished from Contract Demand service. (initial brief, p. 6) North Penn also directs attention to the fact that although the average general rate increase for all zones amounts to 12.18 percent under Tennessee's instant G–11980 rate filing, the increase in the Seller's Option rate for the Northern Zone would amount to 20.57 percent as a result of utilization of the proposed 75% factor. (17:2383–85)

It is quite clear that the entire Tennessee case for its proposed new SO rate, reflecting a 75 percent factor, rests upon its Exh. 44 study—which constitutes an interoffice communication dated April 1, 1957.[29] The Exh. 44 study set forth a tabulation of Tennessee's total estimated Seller's Option contract commitments, amounting to an annual volume of 64,494,600 Mcf. It also estimated the volume of off-peak gas generated for SO customers by certain of the Contract Demand customers. On the basis of these figures, it estimated that an additional average daily capacity of 156,092 Mcf was required for SO customers, this being the additional capacity which had been applied for in Docket G–11107. The estimated 64,494,600 Mcf of annual Seller's Option gas requirements was derived as follows:

[29] It is of interest to note that this memorandum was prepared subsequent to the instant G–11980 rate filing which proposed the mentioned increase in the SO rate.

(*a*) Existing in 1956:

Buyer	*Annual volume (Mcf)*
United Fuel Gas Company	20,400,000
North Penn Gas Company	5,497,800
New York State Natural Gas Corporation	8,160,000
Subtotal	34,057,800

(*b*) Future requirements:

Buyer	*Annual volume (Mcf)*
New York State Natural Gas Corporation	10,036,800
New York State Natural Gas Corporation	20,400,000
Subtotal	30,436,800
Total	64,494,600

(North Penn initial brief, p. 8)

The Exh. 44 study computed that the above-mentioned additional average daily capacity of 156,092 Mcf required for SO customers constituted 88.3% of Tennessee's total Seller's Option contract commitments on an average-day basis, and accordingly concluded that the 88.3% ratio represented the proper "factor applicable to the determination of the Seller's Option rate". By way of supporting the reasonableness of the proposed new SO rate, reflecting a 75 percent factor, Tennessee witness Davis prepared a further study, Exh. 63, which was based entirely upon the above 88.3% ratio. In this latter study Davis assigned to Seller's Option service 88.3% of the transmission cost per Mcf for each zone in which SO service was sold. To this he added the production costs per Mcf to arrive at the total cost per Mcf for SO service. He then multiplied the total cost per Mcf by the deliveries of SO gas in each zone, to determine the total cost for SO service in each zone. Since the revenues computed for SO gas at the proposed new rate, reflecting a 75 percent factor, were approximately equal to the allocated cost thus computed in Exh. 63 for Seller's Option service in each zone, Davis concluded that the reasonableness of Tennessee's proposed new SO rate was satisfactorily established.

The difficulty with the Tennessee position here is that its case for an increase in its SO rate rests upon certain estimates which it made in April, 1957, but which have since become completely obsolete as a result of subsequent developments. The fact is that no facilities at all were constructed by Tennessee during the test year to render Seller's Option service (17:2473), and the situation was unchanged at the time of the Commission's decision in Docket G–11107 dated January 28, 1959, where it stated:

> Tennessee's Seller's Option Service is presently being rendered by means of seasonal off-peak capacity available on its system. (21 FPC 72)

It is true that, pursuant to a temporary certificate issued October 13, 1957 in Docket G–11107, Tennessee had received temporary authority to construct, *but not to operate*, the 156,000 Mcf of average-day capacity requested for the Seller's Option Service. (21 FPC 74) Authority to operate such facilities was not granted until the Commission's final order of January 28, 1959 in Docket G–11107. (21 FPC 83) However, shortly thereafter Tennessee converted the bulk of its Seller's Option service to Contract Demand service. As noted in Tennessee's initial brief (footnote 50, pp. 48–49), United Fuel entered into a

contract with Tennessee to firm up its Seller's Option obligation of 20,400,000 Mcf into a contract demand obligation. and this contract was filed with the Commission on May 11, 1959. On the same day, contracts with New York State Natural were also filed, firming up into a contract demand obligation the Seller's Option obligations shown in Exh. 44 of 8,160,000 Mcf and 20,400,000 Mcf. As a result of this development, the only two deliveries of Seller's Option gas presently being made by Tennessee are: (1) the 5,497,800 Mcf annual obligation for North Penn, and (2) the 10,036,800 Mcf annual obligation for New York State Natural, totalling an average day obligation of only 42,560 Mcf.

Furthermore, Tennessee has since informed the Commission that—

> Based upon experience with certain contract demand customers, estimates of their purchases received from these customers and discussions with these customers Tennessee believes it is reasonable to expect that there will be available on an annual average day basis at least 42,560 Mcf of gas resulting from cut-backs.

This statement was made by Tennessee in an Exh. X3 attached to its application in a recent certificate proceeding, Docket G–18877, filed July 1, 1959. (Item V in the instant proceeding.) In an Exh. X4 attached to the same application (Item W in the instant proceeding), Tennessee referred to the fact that it had already converted 134,136 Mcf of its total average day SO obligations to contracted demand service, and that in order to effect this conversion it had allocated to the newly converted firm service 134,640 Mcf of the average day SO capacity of 156,099 Mcf which it had been authorized to construct by the G–11107 order of January 28, 1959—thus leaving a balance of 21,459 Mcf of average day capacity available for the remaining 42,560 Mcf of average day SO obligations. Tennessee then went on to state the following:

> However, in designing its pipeline system to provide for the additional service proposed herein, it is Tennessee's judgment that since its average day seller's option obligations have been substantially reduced to a relatively small daily quantity (42,560 Mcf), *it is no longer necessary to assign pipeline capacity to this service and instead, this service can be rendered by relying on cut-backs from several of Tennessee's contracted demand customers who can be expected to regularly operate at an annual load factor of less than 100%. In view of the above, seller's option obligations are not included in Tennessee's design day requirements which are used for the purpose of determining pipeline capacity needs.* (Item W, p. 2) [Emphasis supplied.]

Under the circumstances outlined above, it seems clear that the Exh. 44 study upon which Tennessee rested its case for the proposed new SO rate is now quite irrelevant. Similarly the Exh. 63 study, which Tennessee witness Davis used to demonstrate the reasonableness of the proposed new SO rate, is equally defective since it relies and is based upon the Exh. 44 calculation that an additional average daily capacity was required for SO customers amounting to 88.3% of Tennessee's total Seller's Option contract commitments.

Tennessee concedes in its briefs that "the Seller's Option obligations have been substantially reduced due to the conversion of a large part of the Seller's Option obligation to Contract Demand obligations." (reply brief, p. 19) Nevertheless, Tennessee urges that "there still is insufficient off-peak capacity to make all the remaining Seller's Option deliveries" (reply brief, p. 19), and therefore still insists that the proposed increase in its SO rate is justified and fair. In clinging to this position, Tennessee completely ignores and makes no reference

to the representations which it has made to the Commission in the Docket G–18877 certificate proceeding, to the effect that "it is no longer necessary to assign pipeline capacity" to the SO service—quoted above.

As a final argument in its reply brief, Tennessee suggests that the failure to approve the proposed increase in its SO rate

> * * * may very well lead to additional requests for Seller's Option service. Since as we have shown, additional capacity would be required for such purpose, the rate would again have to be adjusted upward. (reply brief, p. 19)

This argument does not merit serious consideration. The determination to be made here may not properly be influenced by speculation as to some remote possibility of what might conceivably happen in the future.

In view of all the considerations outlined above, the Tennessee proposal to increase its SO rate by converting from a 50 per cent to a 75 per cent factor is rejected. It should be noted that in the historical revenue portion of its allocation in Exh. 116 Tennessee, in view of the said SO proposal, departed from the present revenue level with respect to its SO sales—imputing to SO deliveries a demand based on 75% of the demand component of the CD rate at 100% load factor, and thus arriving at a higher revenue figure for SO sales than that actually received on a historical basis. As Tennessee witness Davis testified:

> I adjusted the effective annual demands and revenues under present seller's option rate schedules to reflect the revision being made in the basis of determination of these rates. (3:357)

Since Tennessee's proposal to increase the SO rate is here being rejected, the historical revenue allocation to SO service has been recomputed on the basis of the historic 50 per cent factor in the revised Exh. 116 which is set forth in Appendix Table B at the end of this decision.

FINDINGS AND CONCLUSIONS

Upon consideration of the entire record in this proceeding, the evidence adduced and the briefs filed, the Presiding Examiner finds and concludes, in addition to the findings and conclusions hereinbefore stated, that

(1) The Tennessee system is divided into six rate zones, namely, Southern (Zone 1), Central (Zone 2), Eastern (Zone 3), Northern (Zone 4), New York (Zone 5) and New England (Zone 6). The Commission has not previously determined a method by which Tennessee's cost of service should be allocated among its rate zones and classes of service.

(2) Tennessee operates an integrated pipeline system, in which every portion of the system contributes in one way or another to the effectiveness of the entire system, whether directly or by displacement.

(3) Both Columbia and Consolidated advocate a zone-gate (or zone-by-zone) allocation approach whereby each rate zone is treated as if it were a separate operating entity, and involving the segregation of physical property on the basis of zone boundaries. The zone-gate approach is inconsistent with the basic principles upon which Tennessee's integrated system was designed and is operated. In addition, it accentuates the impact upon cost allocation resulting merely from the historical location of the geographical zone boundaries on the Tennessee system. It is also unduly complex.

(4) Columbia rejects the Commission's long-established *Atlantic Seaboard* method for the classification of fixed costs between demand and commodity, and instead applies to its zone-gate approach a "capacity-credit" technique, designed for the purpose of assigning some portion of fixed costs to interruptible de-

liveries. No justification has been shown in this proceeding for rejecting the *Atlantic Seaboard* method of cost classification. In addition, the capacity-credit method here advocated by Columbia is unduly complicated and contains other inherent defects.

(5) The Mcf-mile approach, which uses system-wide average costs and allocates such costs on the basis of mileage, constitutes, in general, a fair and reasonable method for the allocation of costs between zones on the Tennessee system.

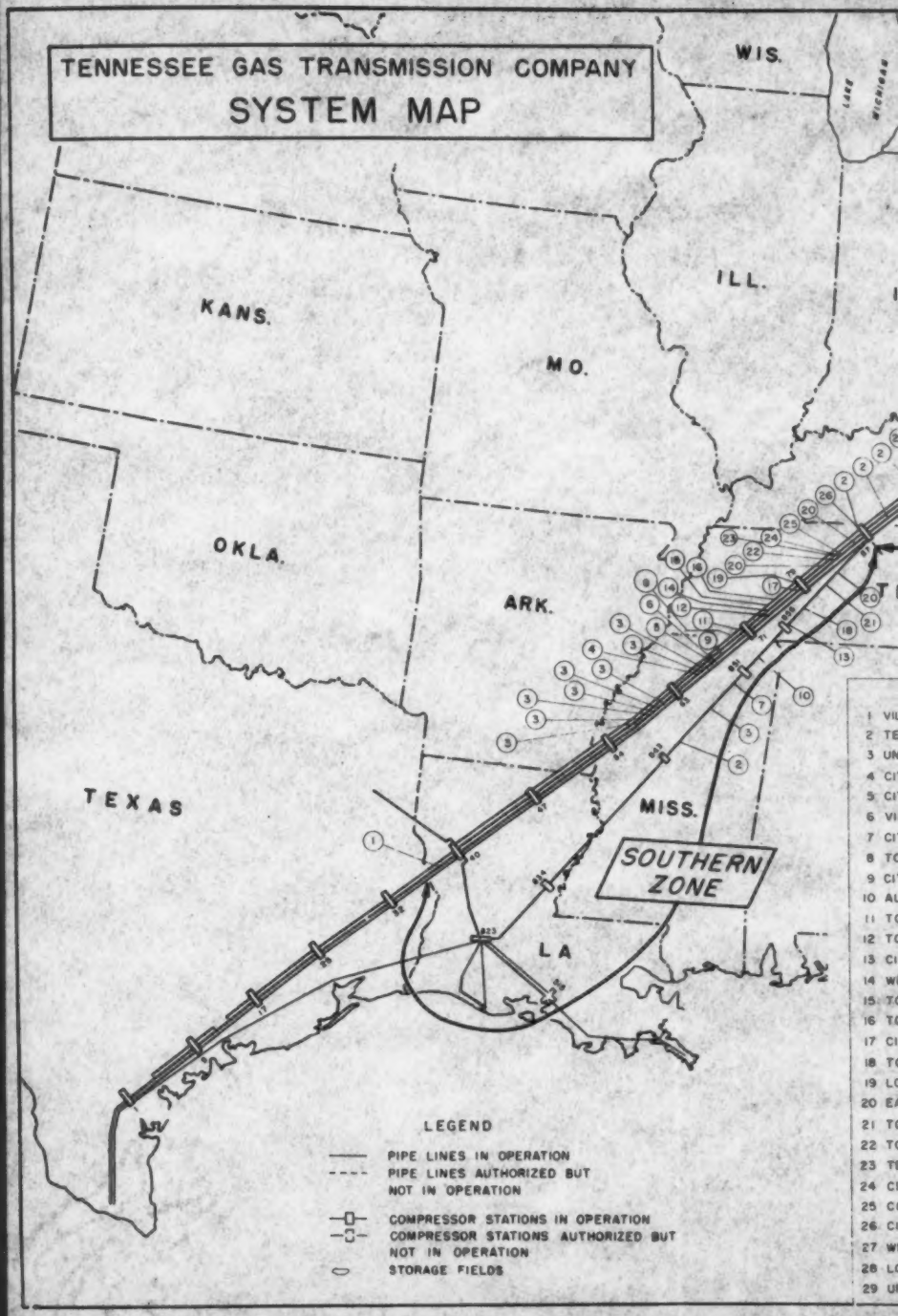
(6) The New England Zone is marked by certain unfavorable characteristics which exert some upward impact upon the cost of service—i.e., the physical presence in the New England Zone of a large amount of small-diameter pipe, and a lower load factor than the other zones on the Tennessee system. These characteristics are not so significant or controlling as to outlaw the use of an Mcf-mile allocation approach for the Tennessee system. However, some limited type of adjustment should be made to the straight Mcf-mile allocation approach in this proceeding, so that the costs allocated to the New England Zone will reflect in some limited manner the excess costs reasonably attributable to such unfavorable characteristics.

(7) The Commission Staff employs the Mcf-mile allocation method, but proposes that the allocated costs determined for the New York and the New England Zones should be adjusted upward to the dollar level of the revenue for these two zones at the Docket G–5259 rates. These adjustments were designed to reflect the low load factor in the New England Zone, plus problems of load distribution and volume of sales with respect to the New York and New England Zones. These Staff adjustments were not adequately supported on the record, and do not provide a satisfactory basis for the necessary adjustment to the straight Mcf-mile approach in this proceeding.

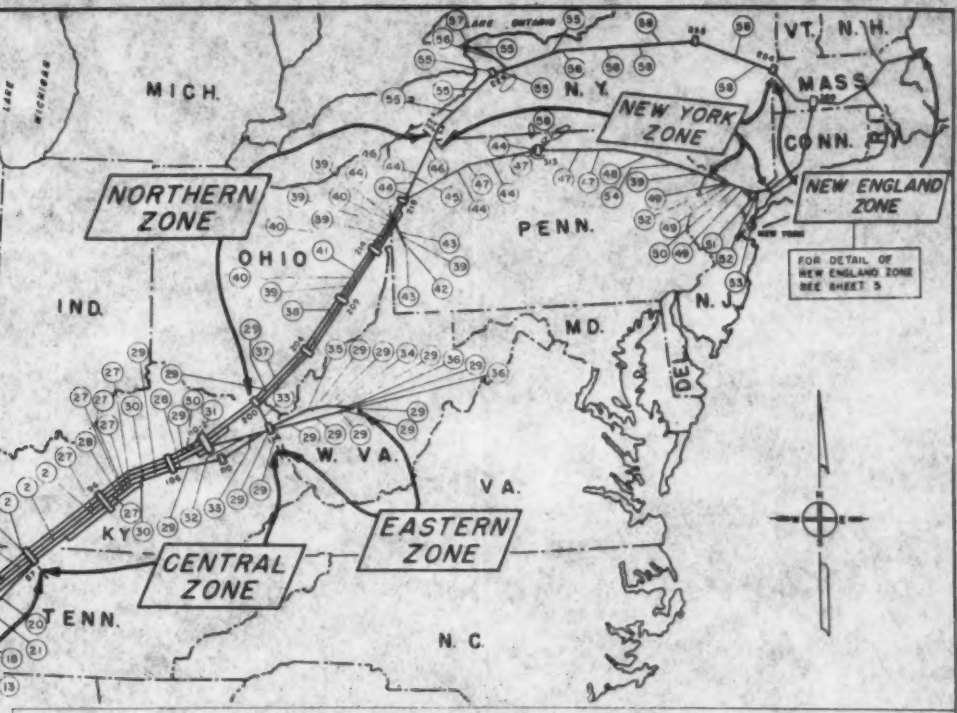
(8) Tennessee allocates costs between zones partly on the basis of mileage, and partly on the basis of historical rate differentials. 50 percent of transmission costs are allocated under the Mcf-mile method, and 50 percent on the basis of historical factors, utilizing Docket G–5259 rate levels applied to 1956 deliveries. This Tennessee method, in general, constitutes a fair and reasonable method for the allocation of costs between zones on the Tennessee system. The Docket G–5259 revenue pattern reflects, basically, the historical allocation pattern which was arrived at in the Tennessee Docket G–1741 zoning settlement of 1952—which represented a compromise split between the results flowing from application of the straight Mcf-mile method and those under the zone-gate approach. Accordingly, to the extent that 50 percent of the transmission costs under the Tennessee method are allocated under the historical Docket G–5259 revenue pattern, the effect is to impose a limited penalty upon the New England Zone, as a rough factor giving recognition to its unfavorable cost characteristics. In addition, in view of the fact that rates have now been collected over the entire Tennessee system for a period of eight years on the basis of the historical allocation pattern first arrived at in the Docket G–1741 zoning settlement of 1952, it makes sense that this historical allocation pattern should be reflected to some extent in the zone allocation levels which are now to be fixed for the future for the Tennessee system.

(9) The Tennessee method for allocation of costs to Transportation Service, utilizing the mileage from the actual points of receipt of transportation gas to the points of delivery, is reasonable.

(10) The Iroquois complaint that the use of the Pennsylvania-New York state boundary as a dividing line between the Northern and New York Zones is unfair and discriminatory has not been supported in this record.


TENNESSEE GAS TRANSMISSION COMPANY
SYSTEM MAP
WIS.
ILL.
KANS.
MO.
OKLA.
ARK.
TEXAS
MISS.
LA
SOUTHERN ZONE
LEGEND
PIPE LINES IN OPERATION
PIPE LINES AUTHORIZED BUT NOT IN OPERATION
COMPRESSOR STATIONS IN OPERATION
COMPRESSOR STATIONS AUTHORIZED BUT NOT IN OPERATION
STORAGE FIELDS

APPENDIX TABLE A



SERVICE CONNECTIONS

1 VILLAGE OF ROBELINE, LOUISIANA
2 TEXAS GAS TRANSMISSION CORPORATION
3 UNITED GAS PIPE LINE COMPANY
4 CITY OF BATESVILLE, MISSISSIPPI
5 CITY OF HOLLY SPRINGS, MISSISSIPPI
6 VILLAGE OF ASHLAND, MISSISSIPPI
7 CITIES OF NEW ALBANY AND PONTOTOC, MISSISSIPPI
8 TOWN OF WALNUT, MISSISSIPPI
9 CITIES OF RIPLEY, BOONEVILLE AND BALDWYN, MISSISSIPPI
10 ALABAMA-TENNESSEE NATURAL GAS COMPANY
11 TOWN OF BOLIVAR, TENNESSEE
12 TOWN OF HENDERSON, TENNESSEE
13 CITY OF SAVANNAH, TENNESSEE
14 WEST TENNESSEE PUBLIC UTILITY DISTRICT
15 TOWN OF LEXINGTON, TENNESSEE
16 TOWN OF PARSONS, TENNESSEE
17 CITY OF LINDEN, TENNESSEE
18 TOWN OF HOHENWALD, TENNESSEE
19 LOBELVILLE GAS COMPANY
20 EAST TENNESSEE NATURAL GAS COMPANY
21 TOWN OF CENTERVILLE, TENNESSEE
22 TOWN OF DICKSON, TENNESSEE
23 TENNESSEE NATURAL GAS LINES, INC.
24 CITY OF CLARKSVILLE, TENNESSEE
25 CITY OF SPRINGFIELD, TENNESSEE
26 CITY OF PORTLAND, TENNESSEE
27 WESTERN KENTUCKY GAS COMPANY
28 LOUISVILLE GAS AND ELECTRIC COMPANY
29 UNITED FUEL GAS COMPANY
30 DELTA NATURAL GAS COMPANY, INC.
31 CITY OF MOREHEAD, KENTUCKY
32 TOWN OF GRAYSON, KENTUCKY
33 INLAND GAS CORPORATION
34 GODFREY L. CABOT, INC.
35 CUMBERLAND GAS CORPORATION
36 HOPE NATURAL GAS COMPANY
37 PIKE NATURAL GAS COMPANY
38 NATIONAL GAS AND OIL CORPORATION
39 MANUFACTURERS LIGHT AND HEAT COMPANY
40 EAST OHIO GAS COMPANY
41 ELLIS T MYERS GAS COMPANY
42 EQUITABLE GAS COMPANY
43 PEOPLES NATURAL GAS COMPANY
44 UNITED NATURAL GAS COMPANY
45 LAKE SHORE PIPE LINE CO.
46 PENNSYLVANIA GAS COMPANY
47 NORTH PENN GAS COMPANY
48 VALLEY CITIES GAS COMPANY
49 PUBLIC SERVICE ELECTRIC AND GAS COMPANY
50 ROCKLAND LIGHT AND POWER COMPANY
51 BROOKLYN UNION GAS COMPANY
52 CONSOLICATED EDISON COMPANY OF NEW YORK, INC.
53 LONG ISLAND LIGHTING COMPANY
54 SCRANTON-SPRING BROOK WATER SERVICE CO.
55 IROQUOIS GAS CORPORATION
56 NEW YORK STATE ELECTRIC AND GAS CORPORATION
57 NIAGARA GAS TRANSMISSION LIMITED
58 NEW YORK STATE NATURAL GAS CORPORATION

TENNESSEE GAS TRANSMISSION COMPANY
ALLOCATION OF F.P.C. STAFF COST OF SERVICE AMONG ZONES AND CLASSES OF SERVICE
TWELVE MONTHS ENDED DECEMBER 31, 1956

Line No.	Particulars	Present Revenue Level: Demand	Commodity: Total	Commodity: Less: Volume Component	Commodity: Delivery	Total Excluding Volume Component	Annual Mcf: Demand	Annual Mcf: Delivered	Average of 3-day Peak Deliveries	Mcf - Miles: Demand
1	TRANSMISSION SYSTEM:									
2	Jurisdictional -									
3	Gas Sales:									
4	Southern Zone -									
5	Contracted Demand Service	$ 555,417	$ 1,366,863	$ 951,463	$ 409,400	$ 964,817	9,385,518	7,873,089	25,759	19,472
6	General Service	5,524,448	13,064,384	9,134,109	3,930,275	9,454,723	93,352,956	75,582,205	261,454	196,820
7	Small General Service	399,589	610,783	427,036	183,747	583,336	6,752,319	3,533,600	32,045	20,729
8	Interruptible Service	31,504	92,018	64,335	27,683	59,187	532,357	532,357		
9	Total Southern Zone	$ 6,510,958	$ 15,128,048	$10,576,943	$ 4,551,105	$ 11,062,063	110,023,150	87,521,251	319,258	237,021
10	Central Zone									
11	Contracted Demand Service	$ 3,673,049	$ 9,905,008	$ 5,872,064	$ 4,032,944	$ 7,705,993	51,963,682	48,589,690	143,527	146,908
12	General Service	123,240	201,005	119,164	81,841	205,081	1,743,505	986,045	5,457	5,134
13	Small General Service	257,553	376,209	224,217	153,992	411,545	3,643,677	1,855,332	14,269	13,282
14	Interruptible Service	31,614	91,170	54,048	37,122	68,736	447,243	447,243		
15	Gabe Plant Deliveries	590,917	1,572,853	939,130	633,723	1,224,640	8,359,569	7,635,208	21,089	18,670
16	Total Central Zone	$ 4,676,373	$ 12,148,245	$ 7,208,623	$ 4,939,622	$ 9,615,995	66,157,976	59,513,518	184,282	183,994
17	Eastern Zone -									
18	Contracted Demand Service	$15,115,082	$ 44,306,033	$25,038,037	$19,267,996	$ 34,383,078	208,977,465	207,182,761	570,033	662,516
19	Interruptible Service	25,840	76,398	43,174	33,224	59,064	357,249	357,249	1,052	1,208
20	Seller's Option Service	403,900	2,368,368	1,349,704	1,018,664	1,742,564	5,584,213	11,168,426	21,692	36,644
21	Total Eastern Zone	$15,544,822	$ 46,770,799	$26,430,915	$20,339,884	$ 35,884,706	214,918,927	218,708,436	602,777	700,370
22	Northern Zone									
23	Contracted Demand Service	$ 7,274,806	$ 19,782,288	$10,093,686	$ 9,688,602	$ 16,963,408	85,105,901	83,522,432	233,397	311,080
24	General Service	649,257	1,692,504	863,581	828,923	1,478,180	7,595,476	7,145,891	22,246	30,035
25	Interruptible Service	22,197	61,305	31,382	30,123	52,320	259,680	259,680	573	733
26	Seller's Option Service	233,542	1,294,220	660,361	633,859	867,401	2,732,151	5,464,301		
27	Harrison Storage Deliveries		681,674	347,816	333,858	333,858		2,878,083		
28	Temporary Peak Service - Contracted Demand	120,060	108,951	55,591	53,360	173,420	1,404,548	460,000		
29	Total Northern Zone	$ 8,299,862	$ 23,621,142	$12,052,417	$11,568,725	$ 19,868,587	97,097,756	99,730,387	256,216	341,848
30	New York Zone									
31	Contracted Demand Service	$ 6,104,523	$ 15,645,243	$ 6,804,850	$ 8,840,393	$ 14,944,916	59,896,531	56,308,235	172,202	276,698
32	General Service	63,911	130,065	56,572	73,493	137,404	627,085	468,114	3,319	4,952
33	Seller's Option Service	408,549	2,227,377	968,878	1,258,699	1,667,248	4,008,597	8,017,194		
34	Emergency Service	57,528	156,836	68,215	88,621	146,149	564,462	564,462		
35	Interruptible Service	7,493	20,429	8,885	11,544	19,037	73,524	73,524		
36	Delivery Agreement	315,945	861,335	374,635	486,700	802,645	3,100,000	3,100,000		
37	Total New York Zone	$ 6,957,949	$ 19,041,485	$ 8,282,035	$10,759,450	$ 17,717,399	68,270,199	68,531,529	175,521	281,650
38	New England Zone									
39	General Service	$ 7,066,348	$ 11,094,994	$ 4,198,622	$ 6,896,372	$ 13,962,720	47,763,282	34,742,425	140,685	257,925
40	Small General Service	365,504	394,704	149,366	245,338	610,842	2,470,537	1,235,960	12,253	23,180
41	Total New England Zone	$ 7,431,852	$ 11,489,698	$ 4,347,988	$ 7,141,710	$ 14,573,562	50,233,819	35,978,385	152,938	281,105
42	Total Gas Sales	$49,421,816	$128,199,417	$68,898,921	$59,300,496	$108,722,312	606,701,827	569,983,506	1,690,992	2,025,988
43	Transportation of Gas of Others:									
44	T-1 Service	$ 1,521,062	$ 2,078,737	$	$ 2,078,737	$ 3,599,799	17,794,480	17,843,232	48,752	68,012
45	T-2 Service	1,161,160	1,231,764		1,231,764	2,392,944	13,584,096	10,573,251	40,000	53,948
46	T-3 Service	954,307	1,237,021		1,237,021	2,191,328	13,194,080	13,230,168	36,148	43,125
47	T-4 Service	2,340,000	3,192,812		3,192,812	5,532,812	27,375,000	27,406,109	75,576	103,989
48	Total Transportation of Gas of Others	$ 5,976,529	$ 7,740,354		$ 7,740,354	$ 13,716,883	71,947,596	69,052,760	200,476	269,014
49	Total Jurisdictional	$55,398,345	$135,939,771	$68,898,921	$67,040,850	$122,439,195	678,649,423	639,036,266	1,891,468	2,295,002
50	Nonjurisdictional -									
51	Industrial Sales	$ 250,651	$ 423,949	$ 399,747	$ 24,202	$ 274,853	4,356,536	3,249,976	12,830	278
52	Sales to Other Utilities	23,772	27,181	25,629	1,552	25,324	413,183	208,368	1,276	38
53	Transportation of Gas of Others	13,684	12,567		12,567	26,191	7,736,978	2,640,273	6,041	638
54	Total Nonjurisdictional	$ 288,047	$ 463,697	$ 425,376	$ 38,321	$ 326,368	12,506,697	6,098,617	20,147	944
55	Sub-Total	$55,686,392	$136,403,468	$69,324,297	$67,079,171	$122,765,563	691,156,120	645,134,883	1,911,615	2,295,946
	Revenues Credited to Cost of Service									
56	Peak Service - General Service - Northern Zone									
57	Peak Service - General Service - New England Zone									
58	Cost Assigned to Storage Service (SS-5), New York Zone (Actual SS-5 Revenues at G-11980 Rates)									
59	Total Transmission System Sales and Transportation									

1/ Plus $3,492 charged to PSC service - line 56.
2/ Plus $388,452 charged to SS-5 service - line 58.
3/ Plus $602,871 charged to PSC service - line 57.
4/ Represents revenues received from such service during refund period, at the 90¢ rate.

5/ It is not conveniently possible, with the data available, to make an actu… method. However, Tennessee's proposed SS-5 rate in its G-11980 rate fili… venues received by Tennessee under the G-11980 rates, amounting to $388,4… to the SS-5 service under the Exh. 65 method. This $388,452 figure is th… in order to provide a short-hand, rough indication of the results which … original Exh. 116.

APPENDIX TABLE B
(Tennessee Exh. 116, as revised to reflect modifications made in this decision)

f - Miles Demand	100 Mcf - Miles Delivered	Distribution of 50% of Transmission Costs on Present Revenue Level			Distribution of 50% of Transmission Costs on Basis of Mcf-Miles (Demand) and 100 Mcf-Miles Delivery			Total Transmission Costs			Production Costs	Total Cost of Service
		Demand	Delivery	Total	Demand	Delivery	Total	Demand	Delivery	Total		
19,472	56,445,291	$ 281,417	$ 207,433	$ 488,850	$ 263,770	$ 224,771	$ 488,541	$ 545,187	$ 432,204	$ 977,391	$ 1,032,737	$ 2,010,128
196,820	565,711,038	2,799,104	1,991,375	4,790,479	2,666,148	2,252,717	4,918,865	5,465,252	4,244,092	9,709,344	9,914,348	19,623,692
20,789	22,504,672	202,462	93,101	295,563	280,798	89,616	370,414	483,260	182,717	665,977	463,513	1,129,490
	3,323,398	15,962	14,026	29,988		15,683	15,683	15,962	29,709	45,671	69,831	115,502
237,021	648,584,399	$ 3,298,945	$ 2,305,935	$ 5,604,880	$ 3,210,716	$ 2,582,787	$ 5,793,443	$ 6,509,661	$ 4,888,662	$ 11,398,323	$11,480,429	$ 22,878,752
146,908	493,234,898	$ 1,861,845	$ 2,043,395	$ 3,904,440	$ 1,990,034	$ 1,964,110	$ 3,954,144	$ 3,851,879	$ 4,007,505	$ 7,858,584	$ 6,373,658	$ 14,232,242
5,134	8,289,368	62,443	41,467	103,910	69,546	33,009	102,555	131,989	74,476	206,465	129,343	335,808
13,282	17,364,394	130,496	78,024	208,520	179,980	69,147	249,067	310,416	147,171	457,587	243,370	700,957
	4,834,127	16,018	18,809	34,827		19,250	19,250	16,018	38,059	54,077	98,666	118,743
18,670	67,765,377	299,403	321,092	620,495	252,906	269,928	522,834	552,309	591,020	1,143,329	1,001,533	2,144,862
183,994	591,508,164	$ 2,369,405	$ 2,502,787	$ 4,872,192	$ 2,492,466	$ 2,355,444	$ 4,847,850	$ 4,861,811	$ 4,858,231	$ 9,720,042	$ 7,806,570	$ 17,926,612
662,516	2,403,262,487	$ 7,658,446	$ 9,762,627	$17,421,073	$ 8,974,551	$ 9,570,027	$18,544,578	$16,632,997	$19,332,654	$ 35,965,651	$27,176,794	$ 63,142,445
1,208	4,182,759	13,093	16,833	29,926	16,363	16,656	33,019	29,456	33,489	62,945	46,861	109,806
36,644	126,531,704	204,646	526,266	730,912	496,384	511,826	1,008,210	701,030	1,038,092	1,739,122	1,464,997	3,204,119
700,370	2,535,976,950	$ 7,876,185	$10,305,726	$18,181,911	$ 9,487,298	$10,098,509	$19,585,807	$17,363,483	$20,404,235	$ 37,767,718	$28,688,652	$ 66,456,370
311,080	1,116,651,550	$ 3,685,968	$ 4,908,980	$ 8,594,948	$ 4,213,928	$ 4,446,616	$ 8,660,544	$ 7,899,896	$ 9,355,596	$ 17,255,492	$10,955,892	$ 28,211,384
30,035	96,265,603	328,963	419,995	748,958	406,858	383,339	790,197	735,821	803,334	1,539,155	987,348	2,476,503
733	3,604,603	11,847	15,263	26,510	9,929	14,334	24,263	21,176	29,617	50,793	34,063	84,856
	82,845,220	118,338	321,161	439,491		329,898	329,898	118,338	651,059	769,399	716,769	1,486,158
	42,462,949		169,158	169,158		169,091	169,091		338,249	338,249	377,527	715,776
	6,125,176	60,831	27,036	87,867		24,391	24,391	60,831	51,427	112,258	60,340	172,598
341,848	1,347,955,101	$ 4,205,339	$ 5,861,593	$10,066,932	$ 4,630,715	$ 5,367,689	$ 9,998,404	$ 8,836,054	$11,229,282	$ 20,068,336	$13,081,939	$ 33,147,275 1/
276,698	896,788,245	$ 3,093,014	$ 4,479,213	$ 7,572,227	$ 3,748,185	$ 3,571,099	$ 7,319,284	$ 6,841,199	$ 8,050,312	$ 14,891,511	$ 7,386,123	$ 22,277,634
4,952	6,983,512	32,382	37,237	69,619	67,081	27,809	94,890	99,463	65,046	164,509	61,404	225,913
	130,017,256	207,002	637,753	844,755		517,741	517,741	207,002	1,155,494	1,362,496	1,051,640	2,414,136
	9,435,095	29,148	44,902	74,050		37,571	37,571	29,148	82,473	111,621	74,042	185,663
	1,223,611	3,796	5,849	9,643		4,873	4,873	3,796	10,722	14,518	9,644	24,162
	50,674,939	160,082	246,599	406,681		201,792	201,792	160,082	448,391	608,473	406,637	1,015,110
281,650	1,095,122,658	$ 3,525,424	$ 5,451,553	$ 8,976,977	$ 3,815,266	$ 4,360,885	$ 8,176,151	$ 7,340,690	$ 9,812,438	$ 17,153,128	$ 8,989,490	$ 26,142,618 2/
257,925	637,914,748	$ 3,580,347	$ 3,494,224	$ 7,074,571	$ 3,493,884	$ 2,540,239	$ 6,034,123	$ 7,074,231	$ 6,034,463	$ 13,108,694	$ 4,557,270	$ 17,665,964
23,180	23,154,007	189,192	124,307	309,499	313,999	92,201	406,200	499,191	216,508	715,699	162,125	877,824
281,105	661,068,755	$ 3,769,539	$ 3,618,531	$ 7,384,070	$ 3,807,883	$ 2,632,440	$ 6,440,323	$ 7,573,422	$ 6,250,971	$ 13,824,393	$ 4,719,395	$ 18,543,788 3/
2,025,988	6,880,216,027	$25,040,837	$30,046,125	$55,086,962	$27,444,284	$27,397,694	$54,841,978	$52,485,121	$57,443,819	$109,928,940	$74,766,475	$184,695,415
68,012	249,992,746	$ 770,685	$ 1,053,245	$ 1,823,930	$ 921,299	$ 995,496	$ 1,916,795	$ 1,691,984	$ 2,048,741	$ 3,740,725		$ 3,740,725
53,948	142,602,494	588,332	624,115	1,212,447	730,766	567,857	1,298,623	1,319,118	1,191,972	2,511,090		2,511,090
43,125	157,838,550	483,524	626,769	1,110,293	584,177	628,529	1,212,706	1,067,701	1,255,298	2,322,999		2,322,999
103,989	377,713,311	1,185,621	1,617,721	2,803,342	1,407,835	1,504,091	2,911,926	2,593,456	3,121,812	5,715,268		5,715,268
269,014	928,147,101	$ 3,028,162	$ 3,921,850	$ 6,950,012	$ 3,644,097	$ 3,695,973	$ 7,340,070	$ 6,672,259	$ 7,617,823	$ 14,290,082		$ 14,290,082
2,295,002	7,808,363,128	$28,068,999	$33,967,975	$62,036,974	$31,088,381	$31,093,667	$62,182,048	$59,157,380	$65,061,642	$124,219,022	$74,766,475	$198,985,497
276	704,987	$ 126,999	$ 12,263	$ 139,262	$ 3,766	$ 2,807	$ 6,573	$ 130,765	$ 15,070	$ 145,835	$ 426,309	$ 572,144
28	36,546	12,045	786	12,831	379	146	525	12,424	932	13,356	27,332	40,688
638	1,142,379	6,993	6,367	13,270	8,642	4,549	13,191	15,545	10,916	26,461		26,461
944	1,883,912	$ 145,947	$ 19,416	$ 165,363	$ 12,787	$ 7,502	$ 20,289	$ 158,734	$ 26,918	$ 185,652	$ 453,641	$ 639,293
2,295,946	7,810,247,040	$28,214,946	$33,987,391	$62,202,337	$31,101,168	$31,101,169	$62,202,337	$59,316,114	$65,088,560	$124,404,674	$75,220,116	$199,624,790
										$ 2,983	$ 509	$ 3,492 3/
										515,004	87,867	602,871 3/
										$ 290,004	$ 98,358	$ 388,432 2/
										$125,212,735	$75,406,890	$200,619,805

s an actual calculation of the costs to be assigned to the SS-5 service under the Exh. 65 rate filing was derived under the Exh. 65 allocation method, and accordingly the SS-5 re- to $388,452, provide a rough approximation of the cost which would actually be allocated gure is therefore regarded as being sufficiently "in the ball park" to be employed here, s which may be expected to flow from the adjustments made in this decision to Tennessee's

(11) In allocating demand costs in this proceeding, demand volumes should be measured on the basis of deliveries during the Staff's three-day peak period of January 16–18, 1957—and not on the basis of average billing demands.

(12) The method of allocation set forth in Exh. 65 is a reasonable method for determining the portion of the total cost of service which Storage Service (SS–5) should bear.

(13) The most reasonable and appropriate method for handling of the Peak Service (PSG) problem in this proceeding is to credit the actual revenues received therefrom during the refund period (*i.e.*, 90¢ per Mcf) to the total cost of service.

(14) The rate for Seller's Option service (SO) should reflect 50 percent of the CD demand charge at a 100 percent load factor basis.

JOSEPH ZWERDLING,
Presiding Examiner.

APPENDIX TABLE C

Results under Tennessee method as revised in the instant decision (appendix table B), compared with results under the other suggested methods

	Columbia interveners (Exh. 109)	Consolidated interveners (Exh. 117)	New England interveners (Exh. 101)	Staff (Exh. 97)	Tennessee method, as revised in appendix table B
Sales:					
Southern Zone	$23,014,151	$22,131,880	$23,182,434	$23,142,175	$22,878,752
Central Zone	17,067,755	16,891,574	17,533,137	17,361,176	17,526,612
Eastern Zone	62,037,218	63,233,762	67,976,129	67,029,625	66,456,370
Northern Zone	32,534,546	32,963,603	33,572,626	32,530,478	[1] 33,150,767
New York Zone	26,613,333	27,937,077	26,394,342	26,367,457	[2] 26,531,070
New England Zone	23,852,427	21,607,221	16,823,086	19,354,014	[3] 19,146,659
Transportation:					
T–1	3,876,348	3,822,104	3,792,768	3,685,135	3,740,725
T–2	3,628,593	3,137,039	2,446,582	2,463,548	2,511,090
T–3	2,024,157	2,079,547	2,420,492	2,352,019	2,322,999
T–4	5,240,534	5,337,174	5,745,624	5,601,519	5,715,268

[1] Representing the figure of $33,147,275 from line 29 of Appendix Table B, plus $3,492 charged to PSG service in the Northern Zone (from line 56 of Appendix Table B).
[2] Representing the figure of $26,142,618 from line 37 of Appendix Table B, plus $388,452 charged to SS–5 service in the New York Zone (from line 58 of Appendix Table B).
[3] Representing the figure of $18,543,788 from line 41 of Appendix Table B, plus $602,871 charged to PSG service in the New England Zone (from line 57 of Appendix Table B).

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

HELMERICH & PAYNE, INC., DOCKET NO. RI60–198

ORDER REQUIRING THE ESTABLISHMENT OF TRUST FUND TO ASSURE REFUNDS AND DIRECTING THAT THE INCREASED RATE BE CHARGED

(Issued February 6, 1962)

On February 26, 1960, Helmerich & Payne, Inc. (Helmerich) tendered a Notice of Change increasing the level of rate from 11.0¢ to 15.0¢ per Mcf for gas produced from the Hugoton Field, Haskell County, Kansas, and sold to Northern Natural Gas Company. By order issued March 23, 1960, in this proceeding, the tender was designated as Supplement No. 3 to Helmerich's FPC Gas Rate Schedule No. 4, and was suspended until August 28, 1960, "and there-

after until such further time as it is made effective in the manner prescribed by the Natural Gas Act."

On August 17, 1960,[1] Helmerich filed a motion requesting that the aforementioned supplement be made effective at the conclusion of the suspension period. In said tender, Helmerich stated it "is not now prepared and does not at the present time intend to furnish a bond as prescribed by Section 4(e) of the Natural Gas Act, should the Commission so require, nor does it intend at this time to furnish its corporate undertaking to make refunds for the reason that it does not presently intend to commence collection of the increased rate subject to refund. The company instead merely requests the Commission to issue its Order Making Effective Proposed Rate Change at the Commission's finally approved rate, effective as of August 28, 1960. This motion is made pursuant to the obligation of the Commission to so act under the authority of Section 4(e) of the Natural Gas Act as determined in *Associated Oil & Gas Company* v. *Federal Power Commission*, United States Court of Appeals, 5th Circuit, July 12, 1960."[2] (Footnote added.)

We believe that Helmerich misconstrues the *Associated* case and that, therefore, its motion is not well-grounded. We do not believe that decision has any effect on the separate and distinct authority of the Commission to require Respondent to charge and collect an increased rate so made effective. Therefore, our action in this matter is not inconsistent with the holding of the *Associated* case and Helmerich's reliance thereon is without foundation.

Furthermore, on December 5, 1960, the Commission issued Order No. 230 in Docket No. R–193 amending Section 154.102 of the Commission's Regulations under the Natural Gas Act, 24 FPC 1058. That order requires that increased rates made effective pursuant to a motion filed under Section 4(e) of the Natural Gas Act shall be charged and collected.

The policy there enunciated and which requires the collection of increased rates, is clearly in accord with the filed rate doctrine as announced by the Supreme Court in the *Montana-Dakota* case.[3] The Court there held that the company "can claim no rate as a legal right which is other than the filed rate, whether fixed or merely accepted by the Commission, and not even a court can authorize commerce in the commodity on other terms." And as the Fourth Circuit in an earlier opinion in *Hope Natural Gas Company* v. *F.P.C.* clearly stated (134 F. 2d 287, 311):

> When rates were filed with the Commission pursuant to Section 4(c) of the Act they become the only lawful rates which the utility could charge or accept (citing cases).

Furthermore, if independent producers were not required to collect increased rates made effective by motion, serious problems would confront not only pipeline purchasers of natural gas and, in turn, distribution company purchasers, but also the Commission itself in the administration of the Natural Gas Act.

The Commission finds:

In view of the foregoing, it would appear appropriate and in the public interest to declare (1) Supplement No. 3 to Helmerich's FPC Gas Rate Schedule No. 4 to be effective as of August 28, 1960, subject to further orders of the Commission in this proceeding; (2) that Helmerich's gas sales made pursuant to the aforementioned Rate Schedule No. 4 and made on or subsequent to August 28,

[1] Supplemented by certain corrections on August 26, 1960.
[2] 280 F. 2d 31.
[3] *Montana-Dakota Utilities Company* v. *Northwestern Public Service Company*, 341 U.S. 246, 251.

1960, shall be pursuant to the rates, terms and classifications set out in said Supplement No. 3, and (3) that Helmerich shall charge and collect only the rates set out in Supplement No. 3 for all gas delivered on and subsequent to August 28, 1960, subject to the terms and conditions herein prescribed.

The Commission orders:

(A) All gas sales on and subsequent to August 28, 1960, and made by Helmerich pursuant to the aforementioned Rate Schedule No. 4, shall be made pursuant to the rates, terms and classifications set out in the aforementioned Supplement No. 3 and, subject to further orders of the Commission in this proceeding, only the rates set forth in said Supplement No. 3 shall be charged and collected for all gas delivered on and after that date.

(B) Helmerich shall refund at such times and in such amounts to those entitled thereto, and in such manner as may be required by final order of the Commission, the portion of the increased rate and charge made effective as of August 28, 1960, found by the Commission in this proceeding not justified, together with interest thereon at the rate of 7 percent per annum from the date of payment to Helmerich until refunded; shall bear all cost of any such refunding; shall keep accurate accounts in detail of all amounts received by reason of the increased rate or charge effective as of August 28, 1960, for each billing period, specifying by whom and in whose behalf such amounts were paid, and shall report (original and one copy), in writing and under oath, to the Commission quarterly, for gas sales to the purchaser and the revenues resulting therefrom, as computed under the rate in effect immediately prior to August 28, 1960, and under the increased rate effective as of August 28, 1960, together with the difference in the revenue so computed.

(C) Within 30 days from the date of issuance of this order, Helmerich shall execute and file with the Secretary of the Commission a trust agreement in the amount and conditioned as set out in paragraph (D) hereof, accompanied by a certificate showing service of a copy thereof upon the purchaser under the rate schedule involved.

(D) Said trust agreement shall be entered into between Helmerich and any bank or trust company used as a depository for funds of the United States Government and said agreement shall be conditioned as follows:

(1) Helmerich, the bank or trust company, and the successors and assigns of each, shall be held and firmly bound unto the Federal Power Commission for the use and benefit of those entitled thereto, with respect to all amounts deposited and the interest thereon, and such bank or trust company shall be bound to repay the purchaser herein and in such manner as may be required by the Commission in this proceeding all or any part of such deposits and the interest thereon as may be required by final order of the Commission.

(2) Such bank or trust company may invest and reinvest such deposits in any form of indebtedness of the United States or any agency thereof and in any form of obligation guaranteed by the United States as the said bank or trust company in the exercise of its sound discretion may select.

(3) Such bank or trust company shall be liable only for such interest as the invested funds described in paragraph (2) above will earn and no other interest may be collected from it.

(4) Such bank or trust company shall be entitled to such compensation as is fair, reasonable and customary for its services as such, which compensation shall be paid by Settlor to such bank or trust company. Said bank or trust company shall likewise be entitled to reimbursement for its reasonable expenses necessarily incurred in the administration of this trust, which reimbursement shall be made by the Settlor. Neither the compensation of such

bank or trust company nor its claim for reimbursement of expenses shall be a charge on the funds deposited hereunder or any interest thereon.

(5) Such bank or trust company shall report to the secretary quarterly, certifying the amount deposited in the trust account for the quarterly period.

If Helmerich, in conformity with the terms and conditions of paragraph (B) of this order, makes the refunds as may be required by order of the Commission, the trust agreement shall be discharged; otherwise it shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TRUNKLINE GAS COMPANY, DOCKET NO. CP62-126

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 6, 1962)

On November 21, 1961, Trunkline Gas Company (Applicant) filed in Docket No. CP62-126 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the calendar year 1962, at a total cost not to exceed $2,500,000, with no single project to exceed a cost of $500,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its existing pipeline system new supplies of natural gas which will be purchased from producers thereof in various areas generally coextensive with said system.

Applicant will finance the subject facilities from funds on hand.

Pursuant to due notice a public hearing was held in Washington, D.C., on January 24, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Trunkline Gas Company, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 29, 1949, in Docket No. G-882 (8 FPC 250).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed, and to conform to the provisions of the Natural Gas Act, and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas purchased from producers thereof during the calendar year 1962 as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before March 1, 1963, a statement under oath showing, by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(6) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(7) The authorization hereinafter granted should be limited to construction during the calendar year 1962, and the total expenditures for facilities authorized to be constructed thereunder should be limited to $2,500,000, with no single project to exceed a cost of $500,000.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Trunkline Gas Company to construct during the calendar year 1962 the proposed facilities hereinbefore described (more fully described in the application filed in this proceeding) and to operate such facilities only to take natural gas from producers who have received authorization from the Commission to sell natural gas to Trunkline Gas Company.

(B) Applicant shall submit, on or before March 1, 1963, a statement under oath showing, by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(C) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed thereunder are hereby limited to $2,500,000, with no single project to exceed a cost of $500,000.

736-330—64——23

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

E. L. CORD, PROJECT NO. 1746

ORDER ISSUING NEW LICENSE (MAJOR)

(Issued February 7, 1962)

Application was filed on December 13, 1960, and supplemented on May 9, 1961, by E. L. Cord, (Applicant) of Reno, Nevada, for a new license under Sections 4(e) and 15 of the Federal Power Act (hereinafter referred to as the Act) for constructed major Project No. 1746 located on Leidy (or Robinson) Creek in Esmeralda County, Nevada, and affecting lands of the United States within the Inyo National Forest and other lands of the United States.

License No. 1 for the project, issued to Applicant on May 1, 1942, for a period of 20 years from October 1, 1941, was amended on May 3, 1949, to reflect a revision in the project works. The license expired on September 30, 1961.

The above-mentiond May 9, 1961, supplement to the application for license shows that an additional hydroelectric turbine and generator of the same rating as the original unit was installed which increased the capacity of the project to 300 horsepower.

An Assistant Secretary of the Interior, in reporting on the application, has advised that no special license provisions in the interest of fish and wildlife resources are considered necessary.

The Chief, Forest Service, acting for the Secretary of Agriculture, who has supervision over the Inyo National Forest, in reporting on the application, has advised that issuance of a new license will not interfere or be inconsistent with the purpose for which the Inyo National Forest was created or acquired if made subject to the terms and conditions contained in Form L–1 (14 FPC 562).

Since the expired license was issued for a period of 20 years terminating on September 30, 1961, the amortization provision provided for under Section 10(d) of the Act was not applicable and, therefore, not included in that license. However, since License No. 2, hereinafter ordered to be issued, is for 5 additional years commencing October 1, 1961, such license is made subject to Section 10(d).

The Commission finds:

(1) The project affects lands of the United States.

(2) The project consists of:

(a) All lands constituting the project area and enclosed by the project boundary or the limits of which are otherwise defined, and/or interest in such lands necessary or appropriate for the purposes of the project, whether such lands or interests therein are owned or held by the applicant or by the United States; such project area and project boundary being more specifically shown and described by a certain exhibit which was filed as a part of the application for license and which is designated as follows:

Exhibit A: Sheet 1 of 1 (FPC No. 1746–7) A map and plan in one sheet entitled: "Existing Hydro Electric Plant for E. L. Cord at Dyer, Esmeralda County, Nevada. Circle L Ranch, Pipeline Plan & Profile", drawn by Nelson Engineering—Civil Engineer, Reno, Nevada, November 30, 1960.

(b) Constructed project works consisting of a reinforced concrete dam 71 feet long and approximately 9 feet high, two 12-inch pipe conduits 97 feet long to a small concrete settling basin, a 12-inch pipe conduit about 1525 feet

long joining the original pipe line, a 10-inch pipe conduit about 19,484 feet long, a cement-block powerhouse containing two 150-horsepower Pelton water wheels connected to two 100-kw generators, a transmission line 5,700 feet in length; and appurtenant electrical facilities; the location, nature and character of which are more specifically shown by the exhibit hereinbefore cited and by certain other exhibits which also formed a part of the application for license and which are designated and described as follows:

Exhibit M: Sheet 1 of 2 (FPC No. 1746–8) a print in one sheet entitled "Electrical Distribution System, General Area Plot Plan, Service Lines & Equipment for E. L. Cord, Esmeralda County, Nevada" prepared by Nelson Engineering, Civil Engineering, Chester H. Elliott, Electrical Engineering, Reno, Nevada, dated May 3, 1961.

Exhibit M: Sheet 2 of 2 (FPC No. 1746–9) a print in one sheet entitled "Electrical Distribution System Equipment, Type & Manufactures Plant Wiring Diagram for E. L. Cord, Esmeralda County, Nevada, prepared by Nelson Engineering, Civil Engineering; Chester H. Elliott, Electrical Engineering, Reno, Nevada", dated May 3, 1961.

(c) All other structures, fixtures, equipment or facilities used or useful in the maintenance and operation of the project and located on the project area, including such portable property as may be used or useful in connection with the project or any part thereof, whether located on or off the project area, if and to the extent that the inclusion of such property as a part of the project is approved or acquiesced in by the Commission; also, all riparian or other rights, the use or possession of which is necessary or appropriate in the maintenance and operation of the project.

(3) The transmission line mentioned in finding (2) (b) above, located entirely on State lands, connects the powerhouse with the distribution facilities at Applicant's ranch, and is part of the project within the meaning of Section 3(11) of the Act.

(4) Applicant is a citizen of the United States and has submitted satisfactory evidence of compliance with the requirements of all applicable State laws insofar as necessary to effect the purposes of a new license for the project.

(5) Public notice of the application has been given. No protests have been received.

(6) The issuance of a new license for the project will not interfere or be inconsistent with the purposes of any reservation or withdrawal of public lands, or with the purposes for which the Inyo National Forest was created or acquired.

(7) The project does not affect any Government dam, nor will the issuance of a new license therefor, as hereinafter provided, affect the development of any water resources for public purposes which should be undertaken by the United States.

(8) Under present circumstances and conditions and upon the terms and conditions hereinafter imposed, the project is best adapted to a comprehensive plan for the improvement and utilization of water-power development, and for other beneficial public uses, including recreational purposes.

(9) The installed capacity of the project is 300 horsepower, and the energy generated by the project is used by Applicant for pumping, irrigation, and general farm uses.

(10) The amount of annual charges to be paid under the new license for the project for the purpose of reimbursing the United States for the costs of administration of Part I of the Act, and for recompensing it for the use, occupancy, and enjoyment of its lands is reasonable as hereinafter fixed and specified.

(11) The exhibits designated and described in finding (2) above conform to the Commission's rules and regulations and should be approved as part of the new license for the project.

The Commission orders:

(A) This new license is issued to E. L. Cord, of Reno, Nevada, (hereinafter referred to as the Licensee), under Sections 4 (e) and 15 of the Federal Power Act, for a period of five years, effective as of October 1, 1961, for the operation and maintenance of Project No. 1746 on Leidy (or Robinson) Creek in Esmeralda County, Nevada, and affecting lands of the United States within the Inyo National Forest and other lands of the United States, subject to the terms and conditions of the Act which is incorporated by reference as a part of this license, and subject to such rules and regulations as the Commission has issued or prescribed under the provisions of the Act.

(B) This license is also subject to the terms and conditions set forth in Form L–1, December 15, 1953, entitled "Terms and Conditions of License for Constructed Major Project Affecting Lands of the United States" (14 FPC 562), which terms and conditions, designated as Articles 1 through 23, are attached hereto and made a part hereof, except for Article 20 therein, and subject to the following special conditions set forth herein as additional articles:

Article 24. The Licensee shall pay to the United States the following annual charges:

(i) For the purpose of reimbursing the United States for the costs of administration of Part I of the Act, $13.00;

(ii) For the purpose of recompensing the United States for the use, occupancy, and enjoyment of its lands, $44.43.

Article 25. Effective October 1, 1961 (the first 20 years of operation of the project under license having been completed on September 30, 1961), six (6) percent per annum shall be the specified rate of return on the net investment in the project for determining surplus earnings of the project for the establishment and maintenance of amortization reserves, pursuant to Section 10 (d) of the Act; one half of the project surplus earnings, if any, accumulated after September 30, 1961, in excess of six (6) percent per annum on the net investment, shall be set aside in a project amortization reserve account as of the end of each fiscal year, provided that, if and to the extent that there is a deficiency of project earnings below six (6) percent per annum for any fiscal year or years after September 30, 1961, the amount of such deficiency shall be deducted from the amount of any surplus earnings accumulated thereafter until absorbed, and one half of the remaining surplus earnings, if any, thus cumulatively computed, shall be set aside in the project amortization reserve account; and the amounts thus established in the project amortization reserve account shall be maintained therein until further order of the Commission.

(C) The exhibits designated and described in finding (2) above are approved as part of this new license.

(D) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313 (a) of the Federal Power Act, and failure to file such an application shall constitute acceptance of this new license. In acknowledgment of the acceptance of this new license, it shall be signed by the licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CROW DRILLING COMPANY, INC., DOCKET NOS. G–6622 AND G–8510; W. H. COCKE, DOCKET NO. G–9570

ORDER DENYING REQUEST FOR ADDITIONAL REFUND ASSURANCE

(Issued February 7, 1962)

On November 24, 1961, United Gas Pipe Line Company (United) filed formal complaints pursuant to Section 1.6 (b) of the Commission's Rules of Practice and Procedure in the above-entitled proceedings. In those complaints, United requests that the Commission order W. H. Cocke (Cocke) in Docket No. G–9570 and Crow Drilling Company, Inc. (Crow)[1] in Docket Nos. G–6622 and G–8510 to furnish either a continuing surety bond or comparable refund assurance in the nature of a trust or escrow agreement covering all sums heretofore collected and hereafter to be collected, subject to refund at the increased rates involved in the respective proceedings herein as a condition precedent to their collecting such increased rates.

Cocke was permitted to collect the increased rate involved in Docket No. G–9570 as of April 1, 1956, subject to refund, after filing a surety bond in the amount of $19,000. United states that due to the increase in rate from April 1, 1956 to September 1, 1961, it has paid Cocke $92,217.96 subject to refund, which is $73,217.96 in excess of the amount of the existing surety bond.

Crow was permitted to collect the increased rate involved in Docket Nos. G–6622 and G–8510 as of April 15, 1955, subject to refund, after filing a surety bond in the amount of $36,000. From April 15, 1955 to September 1, 1961, United states that due to the increase in rate, it has paid Crow an aggregate sum of $80,837.10, subject to refund, which is $44,837.10 in excess of the amount of the existing surety bond.

United contends that if Respondents are permitted to continue to collect their increased rates subject to refund under the existing surety bonds the purpose intended to be accomplished by the Commission when it originally required that surety bonds be filed would be thwarted. United further contends that the Commission in a proper exercise of its discretion should require additional assurance of Respondents as set forth above.

In requiring a surety bond, it has been our policy to require independent producers to file a surety bond in the amount of the estimated additional revenues for one year resulting from the proposed increase in rate. The purpose has been to afford some assurance in addition to the assets of the independent producer that refunds, if required, will be made. We realize, of course, that the proceedings herein have been protracted. Nevertheless, we do not believe that we should change our policy in this regard, or make an exception to such policy under the circumstances presented herein. In making our determination, we have considered both United's desire for additional security and the financial burdens which would be imposed upon Respondents here by a more rigorous bonding requirement. On balance, we conclude that United's request should be denied.

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[1] Effective December 31, 1955, James D. Madole, *et al.* (Madole) succeeded to the interest of Crow. By letter dated February 11, 1959, Crow's FPC Gas Rate Schedule No. 2, as supplemented, involved herein, was redesignated as Madole's FPC Gas Rate Schedule No. 1, as supplemented.

The Commission finds:

United's request for additional assurance by Respondents in the above-entitled proceedings, as set forth in its formal complaints filed on November 24, 1961, should be denied.

The Commission orders:

United's request for additional assurance by Respondents in the above-entitled proceedings, as set forth in its formal complaints filed on November 24, 1961, is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO ELECTRIC COMPANY, DOCKET NO. E-7017

SUPPLEMENTAL ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTGAGE BONDS

(Issued February 7, 1962)

By order issued January 25, 1962, 27 FPC 174, in the above-entitled matter, the Commission authorized El Paso Electric Company (Applicant) to issue and sell at competitive bidding $10,500,000, principal amount of First Mortgage Bonds, Series due 1992, subject, among others, to the provisions set forth in paragraph (B) of that order, as follows:

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

Applicant, on February 7, 1962, filed an amendment, pursuant to the requirements of the afore-mentioned Commission order, setting forth, among other things, that it proposes to accept as providing the lowest annual cost of money to it the bid of Salomon Bros. & Hutzler to purchase the proposed issuance of $10,500,000, principal amount of Bonds, for the price of 100.483% of principal amount, with an interest rate of 4⅝%.

The Commission finds:

(1) Applicant has satisfactorily complied with the requirements of paragraph (B) of the Commission's order issued January 25, 1962 in the above docket, and under the bid it proposes to accept for the Bonds, the price to be received by Applicant therefor and the interest rate thereof are reasonable.

(2) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The price to be received by Applicant for the proposed Bonds and the interest rate thereof under the bid referred to above are approved as reasonable.

(B) The proposed issuance and sale of Bonds referred to above, upon the terms and conditions and for the purposes specified in the application, as supplemented by the amendment referred to above, are authorized, subject only to the provisions of paragraphs (A), (C), (D) and (E) of the Commission's order issued January 25, 1962, in the above docket.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NO. G–16235; PACIFIC NORTHWEST PIPELINE CORPORATION, DOCKET NO. G–16237; COLORADO INTERSTATE GAS COMPANY, DOCKET NO. G–16904

ORDER DENYING APPLICATION FOR ISSUANCE OF SUBPENA DUCES TECUM AND MOTION FOR EXPEDITION

(Issued February 7, 1962)

Counsel for California Gas Transmission Company and Tennessee California Gas Transmission Company (Tenn-Cal),[1] at the hearing held in the above-styled proceedings on January 9, 1962, made an oral application upon the record for the issuance of a subpena duces tecum directed to El Paso Natural Gas Company (El Paso). The requested subpena duces tecum would require El Paso to produce at the hearing the stock records of Pacific Northwest Pipeline Corporation[2] (now merged into El Paso) which reflect the sales and transfers of so-called promotional stock of Pacific Northwest up to the date of its public financing which took place on April 28, 1955.

The examiner presiding at the hearing ruled, in light of the Commission's order issued April 25, 1960, in *East Tennessee Natural Gas Company*, Docket No. G–19530, 23 F.P.C. 629, that he did not have the power or authority to issue a subpena duces tecum in the absence of a prior finding by the Commission that the requested documents are relevant and material to the inquiry. The examiner has referred Tenn-Cal's application to us for determination of the relevancy and materiality of the documentary material sought. With his referral the examiner has certified those portions of the record containing the arguments of counsel relating to the application for subpena.

Without determining that the material sought by the application for subpena duces tecum could not in any circumstances be relevant, we have concluded that the record as certified does not reveal the theory upon which the material is sought or the basis for a claim of relevancy. In these circumstances, the application, in our view, should be denied.

Although we have passed upon the application for a subpena upon the examiner's reference, we note that it is our opinion that the power to issue subpenas is within the authority of the examiner. See Section 7(b) of the Administrative Procedure Act (60 Stat. 241; 5 U.S.C. 1006); Federal Power Commission Rules of Practice and Procedure, Sections 1.23(a) and 1.27(b); *Lee* v. *F.M.B.*, 284 F. 2d 577 (CA 9, 1960); *Penfield Co.* v. *S.E.C.*, 143 F. 2d 746 (CA 9),

[1] The two companies are interveners in the consolidated proceedings.

[2] Pacific Northwest.

cert. denied 323 U.S. 768 (1944). Cf. *N.L.R.B.* v. *Gunaca*, 135 F. Supp., 790 (E.D. Wisc.), aff'd. 230 F. 2d 542 (CA 7, 1956).

On December 20, 1961, the Public Service Commission of Wyoming filed a "Motion for Expedition of Proceedings" in which it requests us to (1) order the examiner not to grant any further recesses until cross-examination has been completed and all intervenors have completed their cases; (2) reconsider a recent ruling permitting Tenn-Cal to cross-examine as to matters not raised by its petition to intervene; and (3) waive the intermediate decision procedure at the conclusion of the testimony, and set the matter for oral argument at an early date. The Wyoming Commission alleges that there have been undue delays in these proceedings and that such delays are injurious to the consuming public of Wyoming.

We cannot pass upon the merits of the Wyoming Commission's allegations but we wish to make it clear that it is our desire to see these proceedings concluded at the earliest possible date. Of course, all parties to the proceedings must be accorded all the legal rights to which they are entitled. However, it has now been one year since this proceeding was reopened. The testimony runs to well over 10,000 pages since the reopening. We are aware that difficult issues are presented in the reopened proceeding and that the line between what is and what is not admissible evidence may often be finely drawn. But that does not mean that irrelevant questioning or prolonged argument should be tolerated. The examiner should make full use of his powers to assure that this is not the case. Further, we admonish counsel for all parties to avoid prolonged arguments and statements and to summarize their positions briefly. We agree with the Wyoming Commission that undue delay in any proceeding is not in the public interest. We expect, therefore, within the limits of due process, that these proceedings may be promptly concluded.

In our opinion it would be unwise to attempt to determine that no further recesses should be granted in these proceedings. We believe that this matter lies more properly in the province of the examiner. He is more familiar with the daily progress of the hearing and the necessities of the parties. We do believe, however, that recesses in this case should be granted only when it has been shown they are essential. We leave this matter to the discretion of the examiner, confident that he will exercise his discretion sparingly.

As to the second request in Wyoming's motion, we are not referred specifically to a recent ruling permitting Tenn-Cal to examine as to matters not raised by its petition to intervene. The Wyoming Commission's Motion does not make it clear whether it objects to an order issued by us or to a ruling by the examiner. We have attempted by our orders to confine the proceedings to those matters which resulted from the modifications in the proposals as a consequence of the decisions of the California Commission. In the conduct of the hearing the examiner shall limit testimony to evidence pertinent and relevant to such matters.

The Wyoming Commission's request for omission of the intermediate decision procedure appears to be premature. We will be better able to pass upon such request when the hearing has been concluded. We may indicate, however, that we feel that it would not be appropriate to dispense with briefs in these proceedings, regardless of whether the intermediate decision procedure is omitted.

The Commission orders:

(A) The application of California Gas Transmission Company and Tennessee California Gas Transmission Company for issuance of a subpena duces tecum be and it hereby is denied.

(B) The "Motion for Expedition of Proceedings" filed by the Public Service Commission of Wyoming be and it hereby is denied.

Commissioners Morgan and Ross, *concurring*, filed separate statements.

MORGAN, Commissioner, *concurring:*

I concur in the denial of the application by California Gas Transmission Company and Tennessee California Gas Transmission Company, subsidiaries of Tennessee Gas Transmission Company, for issuance of subpena duces tecum, and in the denial of the motion for expedition of proceedings by the Public Services Commission of Wyoming. However, it seems to me that more emphatic measures for expedition of this case are or may soon be required.

On December 27, 1960, the original proceedings under these docket numbers had resulted in the issuance of conditioned certificates based upon 3,521 pages of record, including oral argument. The case was reopened by the Commission on a limited basis in July 1961 after the issuance of an order by the California Public Utilities Commission involving matters related to the conditions originally attached to the certificate. The Tennessee subsidiaries, Tenn-Cal and CalGas, petitioned for intervention in the reopened proceedings on the following grounds:

III

SUMMARY

This Commission is now faced with a proposal radically different from that which it considered in its order of December 27, 1960. Not only have the applicants in Docket Nos. G–16235, *et al.*, entered into a fundamentally changed project, but they have also now disclosed their design to use the new Rock Springs project as a vehicle to defeat the CalGas-Edison project.

There can be no doubt that the Rock Springs parties have now discarded their original proposal in favor of a new project. The evidence adduced at the February 1961 hearings before the California PUC reveals that the new project entails sharply *different facilities* from those previously presented to this Commission, with a drastically *altered timetable for construction and deliveries* of gas. The Rock Springs project also has been changed to serve *different market requirements* with gas obtained in significant part from *different sources.* Such gas will be supplied in substantially *reduced volumes,* and at *prices different* than those originally proposed. As a result, the new project raises grave doubts concerning *economic feasibility* and the *adequacy of gas reserves and deliverability*—doubts which cannot be resolved on the basis of the obsolete record compiled regarding the now defunct original proposal.

Moreover, the economic feasibility of the new Rock Springs project is purportedly dependent upon serving the fuel requirements of Edison which are to be served by the CalGas-Edison project. Indeed, in the compliance phase of the hearings before the California PUC, the Gas Companies' exhibits show that loss of the Edison load (which would result from certification of the CalGas-Edison project) would transform an estimated 1962–66 so-called Rock Springs revenue excess of $10,200,000 into a revenue *deficiency* of $63,400,000.

From this, it is clear why the Rock Spring parties have contended that the two projects are mutually exclusive and that certification of the Rock Springs project will preclude certification of the CalGas-Edison project. This contention has been made before both the PUC and this Commission. By both the testimony and pattern of proof before the PUC, the Rock

Springs parties have made plain their contention that Southern California cannot support both the Rock Springs and CalGas-Edison projects. And before this Commission the Gas Companies have stated that "if the Rock Springs project is certificated, this would eliminate any possible justification for such an independent project."

In these circumstances, the Commission must reopen the Rock Springs proceedings for further hearings. With such further proceedings, the Commission should also consolidate the applications for the CalGas-Edison project for comparative and simultaneous hearing and decision. Otherwise, the Commission will effectively foreclose full and unprejudiced consideration of the CalGas-Edison project. [Emphasis supplied in the original.]

On September 13, 1961, the Commission, having become convinced of the Tennessee subsidiary companies' rights to intervene, issued an order allowing such intervention but including a specific limitation:

> Tennessee California Gas Company and California Gas Transmission Company are hereby permitted to intervene in these proceedings subject to the rules and regulations of the Commission; *provided*, however, that their participation shall be limited to matters affecting rights and interests expressly asserted in their petitions to intervene; and *provided* further that permission to intervene shall not be construed as recognition by the Commission that any intervener might be aggrieved by any order entered in these proceedings.

Thus, as of September 13, 1961 the Tennessee subsidiary companies had stated precisely the grounds upon which they felt they were entitled to intervene; and on precisely those stated grounds (and on no others) the Commission had allowed them to intervene and participate to an extent limited by those grounds.

On September 13, 1961, the total number of pages in the transcript stood at 4,976.

Notwithstanding the precision with which the grounds for intervention had been stated and granted, the Tennessee subsidiaries promptly began to explore matters remotely, if at all, related to the grounds upon which they based their intervention. Particularly, they began a lengthy and detailed exploration of their allegation that El Paso and its associates in the pending application were in some way involved in a violation of either the letter or the "spirit" of the antitrust statutes. As a consequence, on October 2, 1961 Colorado Interstate Gas Company filed with the Commission a "Motion for Prescribing Procedure", in which that company moved that the Commission—

> enter an order limiting the participation of two interveners, Tennessee California Gas Transmission Company (Tenn-Cal) and California Gas Transmission Company (CalGas), to those matters which were set forth by them in their joint petition to intervene in these consolidated proceedings filed May 1, 1961, for the reasons that they have not so limited themselves nor have they been so limited by the presiding examiner.

The Commission's discussion of the CIG motion contained the following rationale and conclusion:

> We note that CIG did not allege that the petition to intervene filed by TennCal and CalGas fails to comply with Section 1.8(c) of our Rules of Practice and Procedure which was cited by the movant, nor does it point out a single specific instance of transgression of the limitation contained in our order permitting intervention that the interveners' participation shall be limited to matters affecting rights and interests expressly asserted

in their petition to intervene. Instead of citing a specific instance of transgression, CIG makes only the general allegation that:

"Beginning with hearings starting the morning of September 14, 1961, the day following the granting of intervention to TennCal and CalGas, and extending to the conclusion of that session of hearings held through September 19th, the record is replete with questions obviously not concerned with the interests of TennCal and CalGas as disclosed in their petition to intervene—even as expanded to encompass grounds asserted in the motions for reopening and consolidation."

CIG is asking this Commission to issue an order for the guidance of future proceedings without having stated facts to show that such an order is needed. In the absence of an allegation of such facts, *we deem it unnecessary to admonish that the limitation upon the interveners' participation as contained in the order permitting intervention should be observed. Such observance is implicit in the limitation itself.*

Upon consideration of the matters set forth in CIG's motion and in the answer thereto, we find that the motion should be denied.

It is our view, however, that it is in the public interest and the interest of all parties to conclude the hearing in these proceedings as expeditiously as possible. *We, therefore, entrust the examiner with the duty of seeing that the hearing is not unduly protracted by dilatory tactics or by the introduction of irrevelant or immaterial testimony.* [Emphasis not in the original.]

On November 13, 1961, the total number of pages in the transcript stood at 8,683.

Despite the clarity with which the Commission reaffirmed the limitations on the Tennessee intervenors, and despite the fact that the CIG motion had been denied on merely technical grounds, Tenn-Cal and CalGas have continued, and have been allowed to continue, their exploration of the matters previously complained about, with no visible change in their tactics to the present date. Thus far the result of these explorations has been to show that several years ago a very small fraction of one percent of the outstanding stock of what is now the El Paso system was temporarily owned by CIG and/or two officials of that company; and to suggest that a similarly small fraction of one percent of El Paso stock may have been or may be similarly held. This appears to be the heart of the Tennessee intervenors' contention regarding a possible violation of the "spirit" of the antitrust statutes, and is the basis for their request for a subpena duces tecum in the application now before us.

As of January 30, 1962, the total number of pages in the transcript stood at 12,628 and the end is nowhere in sight.

There are cases which justify the conclusion that "The mountain labored and brought forth a mouse", but this is not one of those cases. Such a comment on these reopened proceedings would serve as an unearned accolade. It is true that the usual preliminaries have been performed in this case with what can only be described as total promiscuity, but thus far there is no evidence of gestation, much less of parturition; and if anything as impressive as a mouse has emerged from this mountainous record (several pounds of which have been certified to the Commission by the examiner and diligently studied), that modest refugee has taken his departure unobserved.

This is not to say that there have been no developments since the intervention of the Tennessee companies which may someday become relevant to these proceedings. Acres of trees have been felled, ground into pulp, transmuted into paper, and now stand by the ton on shelves awaiting inclusion in the record. The manufacturers of ink have not been idle. They too stand ready to supply the

remarkable demands of this case. Children have been born in the interim who, if they are not careful to direct their youthful energies into more productive channels, may emerge from law school 25 years hence to become enmeshed in these maundering proceedings.

Perhaps of greater relevance, the earth has performed more than 140 rotations on its axis since the Tennessee subsidiaries intervened and has accomplished more than a third of its annual journey around the sun. Thus, the passage of sidereal time without a final decision in this case may be the principal—and perhaps the only—product of the reopened proceedings to date.

In any event, this case is now regarded by informed members of the regulated utility industries and of the bar as a prime example of abuse and erosion of the administrative process. It should be brought to a prompt and productive conclusion.

Ample latitude is provided within the framework of the Administrative Procedures Act for this Commission to instruct the examiner and the attorneys in these proceedings regarding the future conduct of the case. If there is misunderstanding between the Commission and participants in the proceedings concerning the Commission's views with respect to the requirements of the public interest, that misunderstanding can properly be removed by written instructions or by conference.

I believe there has been such a misunderstanding, and I believe the public interest requires its immediate removal. If it is not effectively removed by our actions taken today, more forceful measures are available to us and should be used.

Ross, Commissioner, *concurring:*

I concur in the denial of the subpoena duces tecum. Assuming that its subject matter is within the proper scope of inquiry under our order reopening the hearings, absent a specific offer of proof, it would appear a speculative fishing expedition for minutiae whose relevance is obscure.

Surely an intervenor who is seeking to serve the same market must be aware that it may be charged with attempting to delay the administrative process for selfish reasons. Thus it becomes doubly important that it exercise self control in the presentation of its case and clearly spell out for the examiner and all parties the relevancy, scope, and purpose of its cross examination and testimony.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NONACCEPTIBILITY OF RATE FILINGS BASED ON STATE-PRESCRIBED MINIMUM PRICES, DOCKET NO. R–168

ORDER TERMINATING PROCEEDING

(Issued February 7, 1962)*

In *Cities Service Gas Company* v. *State Corporation Commission of Kansas*, 355 U.S. 391, a 1958 per curiam opinion vacating a judgment of the Supreme Court of Kansas, the United States Supreme Court held, in effect, that the State of Kansas could not lawfully fix a minimum price at the wellhead for natural gas sold in interstate commerce for resale. The decision was based on the

*Published in Federal Register on February 14, 1962 (27 F.R. 1368); amended by order issued March 14, 1962, 27 FPC 523.

authority of *Phillips Petroleum Company* v. *Wisconsin*, 347 U.S. 672, and *Natural Gas Pipeline Company* v. *Panoma*, 349 U.S. 44. A week later the Court, citing *Cities Service*, reversed a decision of the Supreme Court of Oklahoma, which had applied the holding in the *Panoma* case, *supra*, to sales of residue gas but not to sales at or near the wellhead. *Michigan Wisconsin Pipe Line Company* v. *Corporation Commission of Oklahoma*, 355 U.S. 425 (1958).

In the above-entitled proceeding the Commission has under consideration proposed rulemaking that would amend its general rules to provide for rejection of any tender for filing pursuant to Section 4 of the Natural Gas Act to the extent that such filing is based upon a state-prescribed or attributed minimum price. The Commission also has under consideration herein certain questions which the above decisions of the Supreme Court appear to raise with respect to rate filings previously made under Section 4 of the Natural Gas Act.

Notice of the proposed rulemaking involved herein was issued on April 28, 1958, and published in the Federal Register on May 2, 1958 (23 F.R. 2973). In giving notice of the proposed rulemaking, the Commission invited all interested parties to submit data, views, and comments in writing concerning such rulemaking. In addition, interested persons were afforded an opportunity to present their views in oral argument before the Commission on July 29, 1958.

We believe that at this late date a rulemaking proceeding would be a cumbersome and inappropriate means by which to exercise our jurisdiction over the matters involved herein. Such matters can more conveniently be decided when properly raised in individual proceedings before us. We recognize, moreover, that a buyer of natural gas who has paid seller on the basis of a state minimum price law has an adequate remedy in an appropriate court in the event that his contract entitles him to a refund as a result of the invalidity of the state minimum price laws.[1] Furthermore, with respect to future rate filings the question appears to be moot, for to the best of our knowledge there are no longer any state minimum price laws in effect. We conclude therefore, that the above-entitled proceeding should be terminated.

The Commission finds:

The proceeding in Docket No. R–168 should be terminated.

The Commission orders:

The proceeding in Docket No. R–168 is hereby terminated.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

SOUTH TEXAS NATURAL GAS GATHERING COMPANY, DOCKET NO. CP62–124

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 7, 1962)

On November 20, 1961, as supplemented on January 15, 1962, South Texas Natural Gas Gathering Company (Applicant) filed in Docket No. CP62–124 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of approximately 65 miles of 16-inch and 6 miles of smaller diameter

[1] *Pan American Petroleum Corp.* v. *Superior Court of Delaware For New Castle County et al.*, 366 U.S. 656 (1961).

pipeline, a 2,500 horsepower addition to Applicant's existing Compressor Station No. 10, and appurtenant facilities, and authority to sell and deliver an additional volume of up to 70,000 Mcf of natural gas per day through the aforesaid facilities to Transcontinental Gas Pipe Line Corporation (Transco), all as more fully set forth in the application and exhibits.

The purpose of the subject application is to effectuate that provision in Applicant's basic contract dated February 17, 1959, with Transco, on file with the Commission as Applicant's FPC Gas Rate Schedule No. 2, which provides for an increase in deliveries from the presently authorized maximum of 140,000 Mcf per day to 210,000 Mcf per day commencing with the 1961–62 winter heating season. The increased volumes of gas proposed to be made available to Transco are intended to augment Transco's supply for its existing customers. No new markets are proposed to be supplied by Transco from these volumes. No question of gas reserves or deliverability is involved under the subject application.

The estimated total cost of the facilities proposed under this application is 3,243,000 which will be financed by the private sale of new securities.

It appears that the rate to be charged for the additional volumes of gas under this application, which rate is provided for in the basic contract of February 17, 1959, is related to the proceedings now pending in Docket No. G–18907 (Docket Nos. G–18638, *et al.*) and that the certificate authorization hereinafter granted to Applicant should be conditioned as to rate, upon the outcome of said proceedings.

Notice of the subject application was published in the Federal Register on December 30, 1961 (26 FR 12786). On January 19, 1962, The United Gas Improvement Company (UGI) timely filed a petition to intervene in this proceeding, which petition was withdrawn by notice filed by UGI on January 30, 1962. Also on January 19, 1962, Transcontinental Gas Pipe Line Corporation filed a petition to intervene in support of the subject application.

Pursuant to the above notice, a public hearing was held in Washington, D.C., on January 25, 1962, at which time and place counsel for the Applicant entered an appearance. Staff counsel requested a recess for one week which was concurred in by Applicant's counsel and granted by the Presiding Examiner.

On February 1, 1962, pursuant to said recess, the hearing reconvened. Transco did not enter an appearance and in view of the favorable action being taken on the application in this proceeding, no further action on Transco's intervention petition appears necessary. No other petitions to intervene or protests to the granting of the application having been received, and no other appearances having been entered, staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, South Texas Natural Gas Gathering Company, a Texas corporation having its principal place of business in Corpus Christi, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in the Examiner's Decision in Docket No. G–17050 (Docket Nos. G–14829, *et al.*) affirmed and adopted by the Commission in its order issued December 1, 1959, in said proceeding (22 FPC 979).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce for resale, subject to the jurisdiction of the Commission, and the construction and operation thereof and the transporta-

tion and sale of natural gas as proposed by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities and the proposed sale of natural gas by Applicant to Transco are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(6) The certificate hereinafter issued to Applicant should be further conditioned upon Applicant's express agreement to file rates, applicable to all gas sold to Transco under the contract dated February 17, 1959, developed by applying the rate-making and cost of service principles employed in the Commission's ultimate decision in Docket No. G–18907 to the data set forth in Exhibit X–1 of South Texas' application in this docket. In the event that a rate lower than the existing rate of 20¢ per Mcf is filed, South Texas should refund to Transco, within 60 days after the effective date of such reduced rate, the amounts collected in excess of such reduced rate from the date of first delivery of the additional volumes of gas for which authority to deliver is granted herein.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, South Texas Natural Gas Gathering Company, to construct and operate the proposed facilities and to sell and deliver to Transcontinental Gas Pipe Line Corporation for resale, as hereinbefore described and as more fully described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are further conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(C) The time within which the facilities hereby authorized shall be constructed and placed in actual operation is hereby fixed at six months from the date on which this order issues.

(D) Said certificate issued by paragraph (A) above and the rights granted thereunder are subject to the following condition: In the event that a condition requiring a reduction in rate is attached to the permanent certificate issued in Docket No. G–18907, within 60 days after the Commission's decision in Docket No. G–18907 becomes final, South Texas shall reduce its presently effective rate for the sale of natural gas to Transcontinental under South Texas' FPC Gas Rate Schedule No. 2 to the level of its average cost of service for such sale, if such cost is lower than the presently effective rate, and within 60 days after the effective date of such reduced rate, shall refund to Transcontinental the

amounts collected in excess of such reduced rate from the date of first delivery of the additional volumes of gas for which authority is sought at CP62-124 to the effective date of such reduced rate. For the purpose of this condition the average cost of service for sales to Transcontinental shall be determined by applying to the data set forth in Exhibit X-1 of South Texas' Application herein as supplemented, the rate-making and cost of service principles employed in the Commission's ultimate decision in Docket No. G-18907.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

ARKANSAS LOUISIANA GAS COMPANY,[1] (FORMERLY MIDSOUTH GAS COMPANY), DOCKET NO. G-17567; ILLINOIS POWER COMPANY, DOCKET NO. G-17984; ST. CHARLES GAS CORPORATION, DOCKET NO. G-18405; LACLEDE GAS COMPANY, COMPLAINANT v. MISSISSIPPI RIVER FUEL CORPORATION, DEFENDANT, DOCKET NO. G-17832

ORDER GRANTING MOTION TO SEVER AND REVERSING SUPPLEMENTAL INITIAL DECISION IN PART

(Issued February 8, 1962)

On December 1, 1961, the Presiding Examiner issued his supplemental initial decision* in these consolidated proceedings in which he found, among other things, that Mississippi River Fuel Corporation (Mississippi) and its responsible officers and directors have willfully and knowingly failed to comply with certificate provisions of the Natural Gas Act (Act) and the Commission's rules pertaining thereto. Accordingly, the Examiner ordered, subject to our review, that the record in this consolidated proceeding be referred to the Attorney General of the United States with a request that criminal proceedings be instituted against Mississippi and its officers and directors, under Sections 20 and 21 of the Act.

Mississippi filed its exceptions to said supplemental decision on December 21, 1961,[2] in which it requested that the Commission consider that part of said supplemental decision which concerns the Examiner's finding of willful and knowing violation of the Act before giving consideration to the other matters and issues in these proceedings. Additionally, on December 22, 1961, Mississippi filed a motion with the Commission[3] asking for severance and early consideration of the issue of whether or not Mississippi had violated the Act. We have found that good cause exists to grant Mississippi's motion for severance and consideration of that single issue, and have given it our due and careful consideration.

Examination of the entire record in these proceedings concerning the matter of whether or not Mississippi installed natural gas facilities designed to increase the daily capacity of its natural gas pipeline transmission system without first having obtained certificate authorization therefor from this Commission left us in doubt whether there was a basis to warrant certification of the record to the Attorney General with a request for the institution of criminal proceedings.

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[1] By order issued October 19, 1961, in Docket No. CP61-334, we authorized Arkansas Louisiana Gas Company to acquire and operate all the facilities of MidSouth Gas Company.

[2] Exceptions were filed by other parties to these proceedings on January 5, 1962.

[3] Mississippi's motion was in the form of a letter sent to the Chairman by the President of Mississippi. Copies of the letter were served on all parties to these proceedings.

*Printed *infra* p. 748.

Thereafter, we had our staff undertake an investigation of the pertinent parts of all past proceedings in which Mississippi was the applicant, and of the applicable books and records of Mississippi contained in its offices at Clayton, Missouri.[4] Additionally, an engineering inspection was conducted at each of Mississippi's compressor stations.

On the basis of the evidence of record, and the supplemental investigation made by our staff, we find that we do not have a basis for referring this matter to the Attorney General for criminal prosecution. Accordingly, we shall reverse the finding of criminal violation and the ordering paragraph referring the record to the Attorney General. We shall, in the near future, consider all other exceptions filed to the Examiner's supplemental decision and make our determination thereon promptly.

Our action herein is not to be construed as a determination by us that Mississippi has complied with all provisions of the Act or the provisions and terms of its filed FPC Gas Tariff.

The Commission finds:

(1) Good cause exists for our separate consideration of the matter of whether or not Mississippi constructed and operated facilities designed to increase the daily capacity of its natural gas pipeline transmission system without first having obtained certificate authority from this Commission in violation of the Act, and Mississippi's motion for severance should be granted.

(2) Finding Paragraph (11) and Ordering Paragraph (H) of the Examiner's Supplemental Decision, issued herein on December 1, 1961, should be reversed.

The Commission orders:

(A) Mississippi's motion for severance filed herein on December 22, 1961, be and the same is hereby granted.

(B) Finding Paragraph (11) and Ordering Paragraph (H) of the Examiner's Supplemental Decision, issued herein on December 1, 1961, be and the same are hereby reversed and held for naught.

Report of Staff Investigation Docket No. G–17567, et al. Mississippi River Fuel Corporation

Pursuant to the Commission's instructions, the alleged violations of the Natural Gas Act, set forth in the Examiner's Decision issued December 1, 1961, Docket No. G–17567, et al., have been investigated by this Bureau. The investigation included a review of the Commission's files relating to certificates of public convenience and necessity issued to Mississippi River Fuel Corporation: an engineering analysis of various system maps and diagrams from the various proceedings; an engineering investigation of Mississippi's main line compressor stations between Perryville, Louisiana and St. Louis, Missouri; and an investigation of Mississippi's records at its main office. Approximately 45 man-days were expended in the investigation. Results of the several parts of the investigation are discussed below.

Review of the Files

Prior to 1946, Mississippi operated a single line (Line No. 1) system from Perryville, Louisiana to St. Louis, Missouri and environs. By order issued August 28, 1946, in Docket No. G–713 (5 FPC 206) Mississippi was authorized

[4] The staff investigation (report attached) did not disclose the construction of any unauthorized mainline transmission facilities by Mississippi. It indicated that by improved flow efficiency, use of higher pressures and construction cross-overs, Mississippi had achieved added flow capacity.

to install and operate partial loops of its original line, and increased compressor horsepower at existing stations.

In order to utilize the partial loops, it was necessary to connect the ends of the loops to the original pipeline. Similarly, by order issued December 8, 1947, Docket No. G–863 (6 FPC 280), Mississippi was authorized to complete the looping of its original pipeline, and add a small increased amount of compressor capacity. The two lines (Line 1 and Line 2) were interconnected and operated at the same pressures.

The proceedings at that time disclosed that the second line (Line No. 2) was capable of operation at pressures in excess of Line No. 1 and that future expansion would be in the form of compressor additions permitting Line No. 2 to be operated at pressures of 720 psig as compared with the 450 psig of Line No. 1.

The Docket Nos. G–1281, et al. proceedings involved main line compressor additions,[1] new delivery points[2] and laterals to new sources of supply.[3] These proceedings proposed increases in the operating pressure of Line No. 2 and in the sales capacity from 266,000 to 450,000 Mcf per day.

The first indication that Mississippi's capacity was greater than 450,000 Mcf per day came in 1957 with the filing of its application Docket No. G–12343. This proceeding revealed that the existing system capacity was actually closer to 500,000 Mcf per day. By means of proposed small minor additions (pipeline loops, No. 3 line and additional compressor facilities) the capacity was to be increased to 515,000 Mcf per day. The Commission's order of August 2, 1957, (18 FPC 106) authorized the installation and operation as proposed. Additional minor facilities authorized November 14, 1958, in Docket No. G–15190 (20 FPC 517) brought the design capacity to 522,000 Mcf per day.

Although the design capacity was 522,000, Mississippi, in the subject proceedings claimed its actual system capacity was 524,000 Mcf per day. The staff claimed a capacity of 534,000 Mcf per day. This latter amount was based, not upon a study of facilities installed, but upon a study of actual deliveries from the system.

Mississippi claims that the increase in capacity, 450,000–to–500,000 Mcf per day is due to an increase in operating pressures, use of Line No. 2 as a "base load" line and a minor increase in flow efficiency due to "pigging." "Pigging" is a term used to describe the insertion of a device (a "pig") into a line for the purpose of cleaning out accumulated debris.

Engineering Analysis

Staff calculations indicate that the increase in operating pressure of Line No. 2 by 35 psig increases its capacity by 40,000-to-50,000 Mcf per day. Line No. 1 is used to supply markets along the route of the pipelines. The "tie" lines installed as a part of the partial looping program permits refilling of Line No. 1 from Line No. 2. Since Line No. 2 is operated at some 300 psig higher than Line No. 1, this "refilling" can be accomplished without further compression. This in turn permits utilization of a greater portion of installed compressor capacity for Line No. 2.

Also our calculations indicate that the "pigging" of Line No. 1 resulted in an increase of flow efficiency of some 1 to 2 percent. This, coupled with an increase

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[1] Docket Nos. G–1281, G–1524, G–1932.
[2] Docket Nos. G–1454, Z–1490, G–1505, G–1510.
[3] Docket Nos. G–1653, G–1755.

in operating pressure from 450-to-465 psig yields an increase in capacity of approximately 5,000 Mcf per day. We also calculated the compressor horsepower required for the increase in flow gas and concluded that the increased flow could be achieved with the authorized compressor horsepower.

A comparison was made of the location of cross-overs used by Mississippi with the loops proposed in Docket Nos. G–713 and G–863 (see amended order issued April 12, 1949, 8 FPC 810). Slight differences in location were found, but actual pipe available differed somewhat from the original proposals, which may account for this. Otherwise the cross-overs generally conformed to plan. The interconnections were not required to be removed when a change in operation of the two lines was authorized (Docket No. G–12343).

Field Investigation

Field inspection, together with an examination of selected corporate records in the offices of Mississippi, disclosed no installation of rated horsepower in excess of that previously authorized by the Commission. The field examination did, however, clearly disclose Mississippi to have increased the discharge pressures at each of its nineteen compressor stations by the upgrading of pipe pressures and the greater utilization of existing authorized horsepower.

The field examination also disclosed the existence of fifty-one interconnections or "cross-overs", each of which are capable of being used to balance the pressure in Line No. 1 by shifting gas being carried at higher pressure in Line No. 2. These fifty-one interconnections can be identified as to their specific location and docket number authorizing their construction except one installed for an emergency operation in 1951 due to bank erosion at a river crossing.

Company Records

Review of the company's records corroborates that Mississippi has constructed connecting facilities and commenced service to two direct industrial customers (Hill Brick Company and Sterling Steel Castings Company) without prior Commission authorization. It was also disclosed that Mississippi has increased its delivery obligations to other direct industrial customers without seeking Commssion approval. However, as required by the Commission's rules, Mississippi did report the deliveries to these customers.[4]

Review of the minutes of the Board of Directors meetings discloses some inconclusive indication that management was aware that facilities proposed at the 450,000 capacity level could be used to yield increased capacity.

Summary

In summary, our investigation does not disclose the construction of any unauthorized main line facilities by Mississippi. It does indicate, however, that by improved flow efficiency, use of higher pressures and utilization of construcion cross-overs, Mississippi has achieved added flow capacity. The approximate amount of the added flow capacity was reported in subsequent dockets and in annual reports of sales.

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[4] The connection of facilities to the two industrial customers was not the subject of the examiner's findings and recommendations. We are advised by the Office of the General Counsel that at the time these facilities were constructed there was controversy as to whether construction of this type required Commission approval and that the legal issue had not been definitely settled in the courts.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

BEN BOLT GATHERING COMPANY, DOCKET NO. G–20032; EAST WHITE POINT GATHERING COMPANY, DOCKET NO. G–20355; ENGEO GATHERING COMPANY, DOCKET NO. G–20356

ORDER DENYING APPLICATION FOR REHEARING

(Issued February 8, 1962)

On January 10, 1962, Ben Bolt Gathering Company (Ben Bolt) filed an application for rehearing of the Commission's order issued herein on December 12, 1961, 26 FPC 825. By that order, we adopted an initial decision of the presiding examiner issued August 11, 1961, granting certificates of public convenience and necessity to Ben Bolt, East White Point Gathering Company (East White Point), and Engeo Gathering Company (Engeo), under subsections (c) and (e) of Section 7 of the Natural Gas Act (Act), authorizing the facilities and sales the companies proposed in their applications. In so doing, we adopted the presiding examiner's determination that Ben Bolt is an "interstate pipeline" within the meaning of Section 154.91(a) of our Regulations under the Natural Gas Act.

Ben Bolt, in its application for rehearing, requests that we modify our December 12, 1961 order by eliminating the determination that it is an interstate pipeline company and as such, subject to the requirements of our Uniform System of Accounts applicable to Class C natural-gas companies, but otherwise leave our order unchanged.

We conclude that Ben Bolt's requests and application for rehearing should be denied. The three basic arguments Ben Bolt advances in support of its requests we consider separately below.

Ben Bolt points to various facts which it says differentiate it from interstate pipelines generally—particularly that it sells gas to Natural Gas Pipeline Company of America (Natural), its purchaser, under a contract and not under a tariff, and that it dedicates specific reserves to its sale to Natural. It further contends that Engeo, East White Point, and Ben Bolt perform essentially the same function, so that Ben Bolt cannot be realistically distinguished from the former two, whom we held to be gatherers.

These arguments are without merit. In classifying a particular company as an independent producer or an interstate pipeline we must look to the nature of the operations. The facts in this case clearly indicate that Ben Bolt is but an extension of the interstate pipeline system of Natural. If Natural had constructed an extension of its pipeline system to take gas from Engeo and East White Point it would have been required to obtain a pipeline certificate to construct and operate such facilities. Such an extension, if constructed by Natural, would be treated as an addition to transmission facilities, not as a gathering operation. We find no reasonable basis for reaching a different conclusion by reason of the fact the facilities were constructed and are being operated by Ben Bolt. The function performed is the same, *i.e.*, the transportation of natural gas in interstate commerce, after the gathering function has been completed by Engeo and East White Point.

Looking at the operations of Engeo and East White Point, it is clear to us that they function as gatherers. If the producers of the gas, rather than Engeo and East White Point, collaborated in collecting gas from various wells and bringing it to a central point in the field for delivery into a pipeline system this operation

would be treated as gathering and the producers would be classified as independent producers. Because Engeo and East White Point perform this function, rather than the producers, we see no reason for holding, as in the case of Ben Bolt, that they are interstate pipelines.

In our view, the facts here justify the conclusion that Engeo and East White Point are reasonably to be classified in a different category from Ben Bolt, as gatherers and not interstate pipelines, since we found in our order that Engeo and East White Point are in substance extensions of the producers and not of any pipeline company.

Ben Bolt also contends that we have ignored the force of our own regulations, our practice thereunder, and court precedents cited by Ben Bolt,[1] requiring that we classify it as a gatherer under such regulations. It contends that by ignoring such matters, we have changed established Commission practices in a manner that is discriminatory and otherwise in disregard of law.

These arguments too we must reject. We are under law empowered to interpret our regulations, as well as our decisions. Indeed, when we issued our Order No. 174 on July 16, 1954, promulgating the regulations in issue, we expressly stated that that action was "subject to our further order," 19 F.R. 4534. Unquestionably, we can properly, on the basis of our past several years' experience in applying the Act and in regulating producers and gatherers in addition to pipelines, interpret and apply our regulations by further order in the manner here undertaken. Our holding herein does not single out or discriminate against Ben Bolt, since it applies equally to all companies similarly situated.

Finally, Ben Bolt contends that contrary to our findings, the cost of Ben Bolt's complying with the requirements of a Class C natural-gas company under our System of Accounts would be unduly burdensome to it, since it would cost the company some $10,000 a year for which it would have no recompense under any tariff, and would reduce its net operating income before federal income taxes by approximately one-third. Ben Bolt points out that the presiding examiner recognized the harmful effects of any reduction in its income.

We conclude that these arguments, even assuming *arguendo* that the regulatory expenses would be as large as Ben Bolt contends, must also be rejected. Compliance with the requirements of the regulation prescribed by law entails costs to the regulated interests, but such costs, like taxes, are part of the price we pay for government under law, and certainly form no basis for dispensing with regulation, any more than with taxes.

The Commission further finds:

The assignments of error and grounds for rehearing set forth in the application for rehearing filed herein present no new facts or principles of law which were not considered by the Commission when it issued its order of December 12, 1961, or which having now been considered warrant any change or modification of said order.

The Commission orders:

The application for rehearing of the Commission's order issued herein on December 12, 1961, filed by Ben Bolt Gathering Company on January 10, 1962, is hereby denied.

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[1] Ben Bolt cites the Commission cases of *Redland Pipeline Company* in Docket No. G–9215, *West Texas Gathering Company* in Docket No. G–14302, and the judicial decision in *PSC of the State of New York* v. *F.P.C.*, 295 F. 2d 140 (CADC), order on rehearing issued August 3, 1961, *id.* 146.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NOS. G–4769, G–12948, G–17929, AND RP60–3

ORDER DENYING PETITION FOR REHEARING

(Issued February 8, 1962)

On January 11, 1962, El Paso Natural Gas Company (El Paso) filed a petition for rehearing seeking reversal of the Commission's order, issued December 27, 1961, 26 FPC 927, adopting the interim order procedure with respect to the issue of a proper rate of return for El Paso in these proceedings and omitting the intermediate decision and fixing dates for filing of briefs with regard to that issue. In its petition El Paso also requests reversal and rehearing of the Secretary's letter order issued December 27, 1961, rejecting the Exceptions of El Paso Natural Gas Company to Presiding Examiner's Ruling on Motion to Certify, and Motion Requesting Opportunity to Present Oral Argument, together with Brief in support thereof, filed on December 19, 1961.

El Paso purports to assert eight categories of error by the Commission as support for its petition and the requests contained therein. The contentions advanced, in the main, restate the arguments presented by El Paso in its 31 page answer to the Staff's motion for interim order procedure and waiver of the intermediate decision. In fact, those same arguments were first repeated by El Paso in its 9 page appeal from the Presiding Examiner's ruling. As is evident from our order issued December 27, 1961, both of those documents, in addition to the record certified to us, were fully considered in arriving at the determinations set forth in that order.

We have reviewed El Paso's categories of error and the numerous contentions thereunder. It is our view that no useful purpose will be served to repeat each of those contentions here.

Basically El Paso contends that it has a "right" to a single decision in these proceedings and that the Commission, because it did not hear the testimony, would find it extremely difficult to "properly analyze and weigh" that testmony without the benefit of a "reasoned and impartial" review of the record by the Presiding Examiner. We deem El Paso's contentions to be without merit.

The public interest under the Natural Gas Act requires that the consumer shall be free of the burden of unjust and unreasonable rates as expeditiously as possible. Further, if the rate of return claimed by El Paso is proper, it is equally in the public interest that such determination be made as soon as possible. It is not our purpose at this point to prejudge in any way the merits of the evidence on rate of return submitted in these proceedings. The record is clear that all parties have had full hearing on that issue. The procedures prescribed by our order issued December 27, 1961, are designed to accomplish these objectives and are therefore necessary and proper to expedite these proceedings and accord substantial justice to all parties.

El Paso also claims that the Commission erred in adopting the interim order procedure here because it (El Paso) only had notice or opportunity for hearing on the issue of rate of return under "normal procedure" and not under interim order procedure. Actually, El Paso had notice as far back as July 25, 1961, immediately after it adduced its direct evidence on the record, that Staff counsel proposed to move for interim order procedure herein (Tr. 2826). The record further shows that California Commission counsel reminded the parties that a

motion for early decision on rate of return had already been filed by that Commission some time before (Tr. 2829). Staff counsel repeatedly stated his intent to move for interim decision on this issue as soon as all evidence thereon was on the record. El Paso presented its rebuttal evidence on November 15, 1961. The staff motions were made the following day. Clearly, El Paso had sufficient notice and opportunity to present and support its claim, now made in this petition, that use of the interim procedure on the rate of return issue requires a "higher rate of return in order to enable El Paso to attract capital" than would be required if such issue is determined in the "normal manner".

El Paso also claims that unless the Commission, in advance of a decision to use the interim order procedure and in advance of a determination on rate of return, reviews a proposal for voluntary recapitalization referred to by El Paso on the record, the Commission will be acting in a manner prejudicial to El Paso and "in violation of express and implied commitments made to investors in El Paso's stock both by the Commission itself and by El Paso in reliance thereon".

We note, first, that El Paso has never presented to us or timely moved for interim decision on any recapitalization proposal prior to decision on rate of return. If any such proposal is part of the evidence in this record, it will, of course, be considered along with the other evidence on this issue. More important this Commission has made no commitments, either expressed or implied, to El Paso's stockholders. This Commission's duty is to serve the public interest in its totality.

Finally, El Paso also claims that it was denied opportunity to present oral argument on the motions, to file a brief thereon, and to file exceptions, and a brief in support thereof, addressed to the ruling of the Presiding Examiner. As heretofore indicated, El Paso was given full opportunity to file an answer to the Staff's motion, and did in fact file a 31 page answer as well as a 9 page appeal from the Presiding Examiner's ruling. All other documents not provided for by our Rules of Practice and Procedure were properly rejected by the Secretary.

The Commission finds:

El Paso's allegations of error in its petition for rehearing filed January 11, 1962, are unsupported and without merit, and such petition should therefore be denied.

The Commission orders:

The petition for rehearing filed by El Paso on January 11, 1962, hereby is denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

ORDER ESTABLISHING THE NATURAL GAS ADVISORY COUNCIL

(Issued February 8, 1962)*

It is hereby determined, in connection with the performance of duties imposed on the Federal Power Commission, that it is in the public interest that a Natural Gas Advisory Council be, and it hereby is established.

1. *Purpose.* The Natural Gas Advisory Council (Council) shall advise and make recommendations to the Commission on matters concerning the regulation of the natural gas industry. The Council shall not advise or make recommendations with respect to any case or controversy pending before the Commission.

*Commission determination issued January 20, 1964, continued Advisory Council for additional two years.

2. *Membership of the Council.* The Council shall consist of members from the following organizations, as indicated below:

American Gas Association—two members
American Municipal Association—one member
American Petroleum Institute and Mid-Continent Oil & Gas Association—one member jointly
Independent Natural Gas Association of America—two members
Independent Petroleum Association of America—one member
National Association of Railroad and Utilities Commissioners—two members
United States Conference of Mayors—one member

The Chairman of the Commission may also appoint one or two members-at-large. In addition, there shall be an alternate appointed for each Council member. Council members will be permitted to bring technical advisors to the meeting with the advance permission of the Chairman of the Commission. The members of the Commission and such staff members as the Chairman of the Commission shall designate will also attend Council meetings.

3. *Selection of Council Members.* All Council members and alternates shall be selected by the Chairman of the Commission. The Council members and alternates from each of the organizations listed in Paragraph 2, *Membership of the Council*, shall be selected from lists (containing at least the number of names requested by the Chairman of the Commission) submitted by the president or other authorized officer of each organization.

4. *Chairman and Secretary for Council Meetings.* The Chairman of the Commission, or in his absence, the Vice Chairman of the Commission, shall act as Chairman of the Council meetings and shall be responsible for opening and conducting the meeting and for adjourning the meeting when, in his judgment, adjournment is in the public interest.

The Chairman of the Commission shall appoint a Secretary from among the members of the Commission staff who shall be responsible for preparing summary minutes of the Council meetings, preparing agenda, notifying members of the meetings, and maintaining all records related to organization, membership and operations of the Council.

5. *Preparation of the Agenda.* Suggestions for agenda items by Council members shall be submitted to the Secretary of the Council and transmitted to the Commission for its consideration. Suggestions received by the Commission from persons other than Council members may, at the option of the Commission, be placed on the agenda. The final selection of items for Council consideration shall be made solely by the Commission.

6. *Notification of Meetings.* The Secretary shall notify each Council member and alternate at least 15 days in advance of scheduled meetings and simultaneously request notification if the member or his alternate does not plan to attend. A copy of the agenda shall be forwarded to each Council member and alternate as far in advance of the meeting as possible, but in any event no later than the date of the notification letter.

7. *Location and Timing of Meetings.* All meetings will convene at the Office of the Federal Power Commission, located at 441 "G" Street, N.W., Washington 25, D.C., unless otherwise directed by the Chairman of the Commission. Ordinarily, these meetings will be held during the regular working hours of the Federal Power Commission. The Council shall meet in October of each year and at other times upon the call of the Chairman of the Commission.

8. *Advice and Recommendations Offered by the Council.* The advice and recommendations of the members of the Council may be presented to the Com-

mission at Council meetings either orally or in written form. Ultimate decisions based on the Council's advice or recommendations are reserved to the Federal Power Commission.

9. *Duration of the Council.* The Natural Gas Advisory Council shall terminate not later than two years subsequent to its date of establishment, unless the Commission determines in writing, not more than 60 days prior to the expiration of such two-year period, that its continued existence is in the public interest. A like determination by the Commission shall be required not more than 60 days prior to the end of each subsequent two-year period to continue the existence of such Council thereafter.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

REJECTION OF SALES CONTRACTS CONTAINING INDEFINITE ESCALATION CLAUSES AND OF APPLICATIONS RELYING UPON SUCH CONTRACTS FOR GAS SUPPLY, DOCKET NO. R-203

ORDER 242

AMENDING REGULATIONS UNDER THE NATURAL GAS ACT

(Issued February 8, 1962)*

In this proceeding the Commission has under consideration the amendment of §§ 154.93, 157.14(a)(10) Exhibit H (v), and 157.25, Subchapter E, Regulations Under the Natural Gas Act, Chapter I of Title 18, Code of Federal Regulations.

By Order No. 232A, issued March 31, 1961 (26 F.R. 2850, 25 FPC 609), the Commission amended section 154.93 of its Regulations so as to provide that indefinite price escalation clauses in sales contracts executed on or after April 3, 1961, for the sale or transportation of natural gas subject to the jurisdiction of the Commission, would be inoperative and of no effect at law. The amendments herein adopted provide for (1) the rejection of contracts containing such indefinite escalation clauses, (2) the rejection of applications by producers for certificates of public convenience and necessity relying for a gas supply upon contracts containing such indefinite escalation provisions, and (3) the Commission's refusal to consider such contracts submitted in support of certificate applications by pipeline companies.

Public notice of proposed rule making was given by publication in the Federal Register on October 10, 1961 (26 F.R. 9732), and by mailing copies thereof to interested persons, including natural gas companies, and to State and Federal agencies. In response to such notice, numerous comments were submitted. These comments have been carefully considered but, for the reasons set forth below, we adhere to the substance of the amendments as originally proposed.

A number of parties contend that the promulgation of these regulations would be unlawful and beyond the powers granted to the Commission by the Natural Gas Act. We conclude, however, that sections 4, 5, and 7 of the Natural Gas Act contemplate that the Commission will refuse to approve contractual provisions found adverse to the public interest. Section 16 of the Act, of

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*Published in Federal Register on February 14, 1962 (27 F.R. p. 1356). Rehearing denied by order issued April 4, 1962, 27 FPC 666. Set aside, *Pan American Petroleum Company* v. *F.P.C.*, 317 F. 2d 796 (CA10–1963); reversed, *sub nom F.P.C.* v. *Texaco Inc.*, 377 U.S. 33 (1964).

course, authorizes the Commission to issue rules and regulations of general applicability found necessary or appropriate to carry out the provisions of the Act.

Protection of the public interest is the touchstone of our regulatory powers under the Natural Gas Act. The Commission's obligation under the Act to the natural gas companies, as one segment of the public whose interest is to be protected, does not compel it to acquiesce in the use of contracts which carry provisions incompatible with a scheme of effective rate regulation. To be sure, the proposed rule will have impact upon contractual practices which have been fairly widespread. But the real issue is not one of "freedom of contract"; the question is whether the rule is rationally related to a condition which requires correction if regulatory objectives embraced by the statute are to be achieved. See *American Trucking Associations* v. *United States*, 344 U.S. 298. In our view, the rule we adopt fully meets this test.

We held in the *Pure Oil* case[1] that indefinite escalation clauses are contrary to the public interest and restated this conclusion in Order No. 232A. Increases in producer prices, triggered by indefinite escalation clauses, have resulted in a flood of almost simultaneous filings. These filings bear no apparent relationship to the economic requirements of the producers who file them. The Natural Gas Act contemplates that prices, to be just and reasonable, be related to economic needs. The elimination of indefinite escalation provisions does not, of course, cut off other avenues by which a producer may make provision for filing for increased rates.

Filings under indefinite escalation clauses have created a significant portion of the administrative burdens under which this Commission is laboring today. The Natural Gas Act contemplates that rate increases shall be sought when there is economic justification, but not that there shall be a chain reaction in a wide area whenever one producer in the area negotiates a contract at a new price level. The Act requires the Commission to give precedence to the hearing and decision of rate increases, but the complexity of indefinite price clauses requires it to spend an undue amount of time in their interpretation and application at the expense of making a prompt determination of the rate issues involved. Accordingly, in protecting the public against waves of increases which have no defensible basis, we also serve the need—which we believe we should take into account—of making the tasks of regulation more manageable.

It has been brought to our attention that section 154.93 of the Regulations, as amended by Order No. 232A, refers to the date of execution of a contract, rather than the filing date (to which we referred in the notice of this proceeding). It is suggested that this point should be clarified. The Commission agrees and has made appropriate changes. In order to conform the language of the amendments to our existing regulations, we have also changed the phrase "price-escalation provisions" to "price-changing provisions".

The Commission, acting pursuant to authority granted by the Natural Gas Act, particularly sections 4, 5, 7, and 16 thereof (15 U.S.C. 717c, 717d, 717f, and 717o), *orders* that Parts 154 and 157, Subchapter E, Chapter I, of Title 18 of the Code of Federal Regulations be amended as follows:

(A) § 154.93 *Rate Schedule Defined*, is amended by adding a provision at the end thereof to read:

> *Provided further*, That any contract executed on or after April 2, 1962, containing price-changing provisions other than the permissible provisions set forth in the proviso next above shall be rejected.

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[1] *The Pure Oil Company*, 25 FPC 383.

(B) § 157.14(a)(10) *Exhibit H—Total Gas Supply Data* (v), is amended by adding a proviso at the end thereof to read:

Provided, further, however, That any contract executed on and after April 2, 1962, and filed in support of an applicant's gas supply showing will be given no consideration in determining adequacy of gas supply if it contains any price-changing provisions other than those defined as permissible in § 154.93 hereof.

(C) § 157.25 *Necessary exhibits, Exhibit B, Contracts,* is amended by deleting all the language after the first sentence thereof, ending with the words "Natural Gas Act", and inserting in lieu thereof the following:

On or after April 2, 1962, the application shall be rejected if any contract submitted in support thereof contains any price-changing provisions other than those defined as permissible in § 154.93 hereof.

(D) These amendments shall become effective on April 2, 1962.

(E) The Secretary of the Commission shall cause prompt publication of this order to be made in the Federal Register.

Commissioner O'Connor *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

INDEPENDENT PRODUCERS OF NATURAL GAS, DEFINITION OF—TEMPORARY AUTHORIZATIONS, PROCEDURE, DOCKET NO. R-206

ORDER NO. 243

AMENDING §§ 154.91 AND 157.28 OF REGULATIONS UNDER THE NATURAL GAS ACT

(Issued February 8, 1962)*

In this proceeding the Commission has under consideration (1) a redefining of the term "independent producer" as the term is used in Parts 154 and 157 of its regulations, and (2) a revision of its procedures with respect to the issuance of temporary authorizations to independent producers pursuant to section 7(c) of the Natural Gas Act.

The definition of an "independent producer" set forth in the margin[1] is of particular significance because we have provided for simplified regulations for producers as distinguished from pipeline companies. Thus, producers are exempt from the comprehensive reporting and accounting obligations required of the pipeline companies.[2]

We have learned from experience however, that some companies operate lines for the interstate transportation of natural gas under circumstances which require that they be more strictly regulated. If a company is engaged in activities which go beyond production and gathering, the public interest requires that it be regulated as a pipeline company.

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*Published in Federal Register on February 14, 1962 (27 F.R. p. 1356).

[1] Sec. 154.91(a) provides:

Definition: An "independent producer" as that term is used in this part means any person as defined in the Natural Gas Act who is engaged in the production or gathering of natural gas and who transports natural gas in interstate commerce or sells natural gas in interstate commerce for resale, but who is not primarily engaged in the operation of an interstate pipeline.

[2] See Order No. 174–B, 13 FPC 1576, ordering clause (D), at page 1585.

Before a producer may begin service under a temporary authorization issued pursuant to § 157.28 there must be on file an effective rate schedule covering the proposed service filed not less than 30 days prior to the date service is to begin. However, in order to speed the initiation of emergency operations, subsection (d) of the rule provides an automatic waiver of the 30-day filing requirements of §§ 154.92(b) and 154.94(b). The Commission believes that in the present circumstances it should itself consider applications for waiver. Accordingly, we order herein the revocation of § 157.28(d) which reads as follows:

> (d) Notice by the Secretary of the acceptance of the rate filing and the statements made under this section shall constitute a waiver by the Commission of the 30-day advance filing requirements of §§ 154.92(b) or 154.94 (b), and the proposed temporary sales or transportation may proceed forthwith.

Since a currently effective delegation of authority to the Secretary[3] to issue the notice provided for in the revoked section is no longer necessary, it should be revoked as herein provided.

The Commission finds:

(1) Amendment of the Regulations as herein ordered is appropriate and necessary for carrying out the provisions of the Natural Gas Act.

(2) The amendments herein ordered represent matters of practice and procedure which do not require notice or hearing under section 4(a) of the Administrative Procedure Act.

(3) The reasons for the amendments herein adopted, as expressed above, require that they be made effective as hereinafter ordered.

The Commission, acting pursuant to authority granted by sections 4, 7, and 16 of the Natural Gas Act (15 U.S.C. 717c, 717f, 717o), *orders:*

(A) Parts 154 and 157 of Subchapter E, Regulations Under the Natural Gas Act, Chapter I of Title 18 of the Code of Federal Regulations, are amended as follows:

1. § 154.91, subsection (a) is amended to read as follows:

> (a) *Definition.* An "independent producer" as that term is used in this part means any person as defined in the Natural Gas Act who is engaged in the production or gathering of natural gas and who sells natural gas in interstate commerce for resale, but who is not engaged in the transportation of natural gas (other than gathering) by pipeline in interstate commerce.

2. In § 157.28, subsection (d) is revoked.

(B) The above-described delegation of authority to the Secretary issued December 26, 1956, 22 F.R. 12, is revoked effective April 2, 1962.

(C) The amendments prescribed by paragraph (A)1, above, shall become effective upon the issuance of this order.

(D) The Secretary shall cause prompt publication of this order to be made in the Federal Register.

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[3] Issued Dec. 26, 1956, 22 F.R. 12, and included in the Commission's Statement of Organization, paragraph 5(a)(13), 21 FPC 601 at 604.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. CP62-108

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 8, 1962)

On October 30, 1961, as supplemented on November 2, 1961, and November 27, 1961, Transcontinental Gas Pipe Line Corporation (Applicant) filed in Docket No. CP62-108 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of two 4-inch taps located on Applicant's 12-inch Woodbury Line and 20-inch parallel Marcus Hook Loop, respectively, at mile-post 12.49 on each line, in Gloucester County, New Jersey, all as more fully set forth in the application, as supplemented.

The proposed taps will be used as additional delivery points to provide gas service to South Jersey Gas Company (South Jersey), an existing customer, for resale to Shell Chemical Company (Shell Chemical). South Jersey desires to render service to Shell Chemical, a new industrial customer, on a firm basis, which service South Jersey would be unable to provide from its existing facilities

South Jersey proposes to construct and own all facilities between the proposed taps and the Shell Chemical plant, including a meter station to be operated by Applicant. The meter station will be located adjacent to Applicant's lines at the subject taps. The acceptance for filing by Applicant of a revision of Section 5(a) of the General Terms and Conditions of its FPC Gas Tariff, Original Volume No. 1, renders unnecessary any consideration of the request in the instant application for waiver of the former provision in said Section 5(a) requiring the installation of measuring facilities at Applicant's own expense.

The proposed volumes of natural gas which will be sold and delivered through the subject facilities will come out of South Jersey's presently authorized allocations sold to it under Applicant's rate schedules on file with the Commission.

Applicant estimates the cost of the proposed facilities to be $3,500, which will be financed from general funds.

Pursuant to due notice, a public hearing was held in Washington, D.C., on January 31, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Transcontinental Gas Pipe Line Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of November 18, 1948, in Docket No. G-1143 (7 FPC 145).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission as integral parts of Applicant's existing system, and the

construction and operation thereof by Applicant are subject to the requirements of Subsection (c) and (e) of section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of said Regulations, and that the construction of the facilities authorized by this order should be completed and said facilities placed in actual operation within six months from the date on which this order issues.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Transcontinental Gas Pipe Line Corporation, to construct and operate the proposed facilities as hereinbefore described, all as more fully described in the application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of said Regulations.

(C) The facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within six months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

UTAH POWER & LIGHT COMPANY, PROJECT NO. 696

ORDER DENYING APPLICATION FOR AMENDMENT OF LICENSE (MAJOR)

(Issued February 8, 1962)

Application was filed May 23, 1961, by Utah Power & Light Company, licensee for major Project No. 696, located on American Fork Creek in Utah County, Utah, and affecting lands of the United States within the Uinta National Forest, for amendment of the license to exclude therefrom the transmission line between the Upper American Fork Plant and the transformer house at the mouth of American Fork Canyon.

The 6600-volt line sought to be excluded from the license serves primarily to transmit project energy and is required for project operation, carrying more than 95 percent of the project energy to the interconnected transmission system.

By letter dated October 4, 1961, the licensee was advised that according to a study made by the Commission staff the line is part of a project within the meaning of Section 3(11) of the Federal Power Act and should remain under license, and it was requested to file any additional information in support of its application within 30 days from the date of the letter. By letter dated November 16, 1961, the Commission was informed that the licensee had no additional information to file in support of its application.

The Commission finds:

The line sought to be excluded from the license is part of Project No. 696 within the meaning of Section 3(11) of the Federal Power Act. Consequently, the application for amendment of the license should be denied.

The Commission orders:

The aforesaid application for amendment of the license for Project No. 696 is denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CONTINENTAL OIL COMPANY (OPERATOR), ET AL., DOCKET NOS. G–15170, G–15171, G–18750, RI60–194, RI61–458, G–19027, RI60–160, RI61–285, AND G–16966

ORDER ACCEPTING OFFER OF SETTLEMENT, SEVERING AND TERMINATING PROCEEDINGS AND PROVIDING FOR REFUNDS

(Issued February 9, 1962)

On December 12, 1961, Continental Oil Company, for itself and for other parties of interest (hereinafter referred to collectively as Continental), tendered for filing an Offer of Settlement, pursuant to Section 1.18(e) of the Commission's Rules of Practice and Procedure, of the rate suspension proceedings involved in the above-entitled matters. Included in its Offer of Settlement are three proposed increased rates which Continental requests be permitted to become effective without suspension. The sales involved in the Offer of Settlement all concern Continental's jurisdictional sales of natural gas to Texas Eastern Transmission Corporation (Texas Eastern) from Texas Railroad Commission District Nos. Two and Six.

The suspended and proposed rate changes which are the subject of this Offer of Settlement are as follows:

Rate schedule—Supplement No.	Docket No.	Increased rate—¢/Mcf at 14.65 psia	Date effective subject to refund	Settlement rates
84–9	G–15170	13.8733	10/29/58	13.8733
114–12*	G–15171	13.8733	10/29/58	13.8733
125–10*	G–15171	[1] 14.3733	10/29/58	14.3733
11	G–18750	[1] 15.0432	11/18/59	14.3733
12	RI60–194	[1] 15.3765	8/21/60	14.3733
13	RI61–458	[1] 15.7099	9/27/61	14.3733
137–10		13.8733	(proposed in the offer)	13.8733
139–6*		13.8733	(proposed in the offer)	13.8733
141–8*		13.8733	(proposed in the offer)	13.8733
169–3 and 4	G–19027	14.6	1/6/60	14.6
5	RI60–160	14.8	7/29/60	14.6
6	RI61–285	15.0	5/22/61	14.6

*(Operator), *et al.*
[1] Includes 0.5¢ per Mcf allowance to Continental for dehydration and central point delivery.

Under the terms of the offer, Continental agrees to eliminate the favored-nation and price redetermination provisions from the subject contracts. Under Rate Schedule Nos. 84, 114, 137, 139 and 141 Continental proposes to insert schedules of three 0.5¢ per Mcf escalations above the 13.8733¢ per Mcf settlement rates at five-year intervals beginning February 5, 1963. Under Rate Schedule Nos. 125 and 169 Continental proposes to insert schedules of three 0.5¢ and 1.0¢ per Mcf escalations above the respective 14.3733¢ and 14.6¢ per Mcf settlement rates occurring at five-year intervals beginning February 5, 1963 and November 1, 1963. All of the afore-mentioned rates are total rates including any tax reimbursement.

As justification for the offer, Continental contends that the favored-nation and price redetermination provisions of the contracts are valuable to Continental as a means of protection against inflation. In addition, Continental states that the settlement rates are below the level of initial prices for gas sold in the same areas. The offer is consistent with the Commission's announced policy in the Second Amendment to Statement of General Policy No. 61–1.

Docket Nos. G–15170 and G–15171 were consolidated for hearing purposes with Docket Nos. G–16966, a Section 5(a) general investigation.

Texas Eastern concurs in and approves the Offer of Settlement and adverts to the similarity of previous offers of settlement pertaining to jurisdictional sales of gas to Texas Eastern which have been accepted by the Commission. No opposition to the Offer of Settlement has been expressed.

In our judgment, settlement of these proceedings in accordance with the Offer of Settlement is desirable in the public interest and appropriate in carrying out the provisions of the Natural Gas Act. Continental is proposing to eliminate all favored-nation and price-redetermination clauses in its contracts herein involved with Texas Eastern, to waive all its future rights and benefits thereunder and to convert the annual escalations now provided in the contracts to fixed escalations, and provided in its offer.

However, we desire to make it clear that acceptance of this Offer of Settlement shall not be construed as approval of any future increased rates proposed by Continental under the fixed escalation provision or otherwise.

The Commission finds:

(1) Good cause has been shown for severing Docket Nos. G–15170 and G–15171 from the consolidated proceedings in Docket Nos. G–16966, *et al.*, and for terminating the proceedings in Docket Nos. G–15170, G–15171, G–18750, RI60–458, G–19027, RI60–160, RI61–285, and RI60–194.

(2) The proposed settlement of these rate proceedings on the basis described herein, as more fully set forth in the Offer of Settlement filed with the Commission by Continental on December 12, 1961, is in the public interest and appropriate to carry out the provisions of the Natural Gas Act and should be approved by the Commission and made effective as hereinafter ordered.

The Commission orders:

(A) Docket Nos. G–15170 and G–15171 are hereby severed from the consolidated proceedings Docket Nos. G–16966, *et al.*

(B) The Offer of Settlement filed by Continental on December 12, 1961, is hereby approved in accordance with the provisions of this order.

(C) Continental shall execute with Texas Eastern amendments to the gas purchase contracts to implement the provisions of the Offer of Settlement and file with the Commission within 30 days from the issuance of this order such amendments as supplements to the contracts involved.

(D) Within 45 days from the date of issuance of this order, Continental shall refund to Texas Eastern the difference between the amounts collected from Texas

Eastern and the rates agreed upon in the Offer of Settlement, together with simple interest at the rate specified in the respective agreement and undertaking from the respective dates of receipt of said excess amounts by Continental to the date of refund. Continental shall bear all costs incidental to the making of such refunds.

(E) Within 60 days from the date of issuance of this order, Continental shall report to the Commission in writing and under oath the details of its calculations resulting in refunds ordered pursuant to paragraph (D) above, together with copies of releases from Texas Eastern with respect to such refunds.

(F) The proceedings in Docket Nos. G–15170, G–15171, G–18750, RI60–194, RI61–458, G–19027, RI60–160 and RI61–285 upon compliance with paragraphs C, D and E, above, are hereby terminated.

(G) The acceptance of this Offer of Settlement is without prejudice to any findings or determinations that may be made in any proceedings, which are presently being heard, or in any proceedings now pending or which may be hereafter instituted.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

SOCONY MOBIL OIL COMPANY, INC., DOCKET NO. G–13780

ORDER REDUCING INITIAL PRICE AND ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 9, 1962)*

This proceeding comes before us for reconsideration and redetermination in the light of *Atlantic Refining Co.* v. *Public Service Commission*, 360 U.S. 378 (*Catco*) by virtue of the Supreme Court's instructions in *Public Service Commission* v. *F.P.C.*, 361 U.S. 195. Our orders of July 27, 1961 and September 25, 1961, set aside the certificate heretofore issued to Socony (see *Transcontinental Gas Pipe Line Corp.*, 20 FPC 264) and prescribed procedures providing Socony a further opportunity to justify its proposed initial rate as being in the public interest. Socony did file one exhibit and the written testimony of one witness. Under the procedures prescribed by our order the purchaser herein Transcontinental Gas Pipe Line Corporation filed a response to Socony's evidence; Long Island Lighting Company, Philadelphia Electric Company, and The United Gas Improvement Company ("intervenors") filed a statement of position, one exhibit and the written testimony of one witness; and staff counsel filed a motion requesting an order reducing Socony's initial price and ordering refunds. No participant has suggested a need for cross-examination of the written and verified testimony submitted by Socony and the intervenors. Nor has any party answered or objected to staff counsel's motion as provided for by Section 1.12(c) of our Rules of Practice and Procedure. We shall grant staff's motion. Since the motion was not contested, and in view of our recent analysis in Opinion No. 351 (*Continental Oil Co.*, 27 FPC 96, issued January 22, 1962) we need discuss the issues but briefly.

In determining the "in line" price we must look to prices at the time of Socony's contract with Transco, in 1957, for gas produced in Texas Railroad District No. 3. Here, Socony produces and gathers its gas in the High Island Block 10 Field, offshore Texas, and pays 2 cents per Mcf (at 15.025 psia)

*Motion for stay granted by order issued March 30, 1962, 27 FPC 657. Rehearing denied by order issued April 6, 1962, 27 FPC 675. Petition for Review dismissed, *Socony Mobil Oil Company* v. *F.P.C.* (CADC No. 17057). [Unreported]

for transportation to a delivery point in Louisiana. Both staff and intervenors recognize that the in-line price for this sale should exceed the in-line price for a delivery at the offshore platform to the extent of the actual 2-cent line rental.

In our judgment, for 1957, Socony's contract price of 22.8 cents per Mcf is clearly out of line; a total price not exceeding 18 cents per Mcf (at 14.65 psia) would be "in-line" for the gas involved in this proceeding upon delivery in Louisiana and before deduction of the contractual line rental. Interveners' evidence suggests a somewhat lower "line". But the rate schedules cited by interveners do not include certain 1956 contracts which covered part of coastal Transmission Corporation's original gas supply and are cited in staff's motion. See *Houston Texas Gas & Oil Corp.*, 16 FPC 118. We feel these prices should be given some weight in determining the "in-line" price in the public interest.

Finally, Socony presented historical cost evidence purporting to show a direct allocated unit cost of 30.79 cents per Mcf for this High Island gas alone. Socony filed no brief and has not attempted to expound a proper policy which might utilize such cost data, even were we to accept Socony's calculations. In our judgment, it is not feasible to use the cost figures adduced by Socony in redetermining this case. The results of attempting to determine "costs" for each field are too well known to bear extended discussion. As staff points out the ratio of intangible drilling costs, presented by Socony for the 7 productive High Island wells, to the reserve estimates for the pools in which these wells are completed vary from 1 cent per Mcf to 89 cents per Mcf. A system of regulation based on field-by-field cost studies would unduly depress prices in "bonanza" fields—upon which the public heavily relies—and approve excessive prices for marginal production.

Our regulation of producers teaches us that costs should be considered only for aggregates large enough to reflect representative conditions of properties We cannot, here, find the estimated High Island reserves of some 50 million Mcf sufficiently large to give High Island costs any significance standing alone. Since Socony has made no attempt to demonstrate that its isolated cost experience at High Island is representative of experience for other properties, other operators and significant volumes of production in the area, we cannot soundly give any weight whatever to its "cost" showing, and we need not do so. See *Covington & Lexington Turnpike Co.* v. *Sanford*, 164 U.S. 578, 596; *San Diego Land & Town Co.* v. *Jasper*, 189 U.S. 439; *Baltimore & Ohio Rail Road Co.* v. *United States*, 345 U.S. 146.

No controversy outside the price question has been raised in this certificate proceeding. Accordingly, we shall issue Socony a permanent certificate.

The Commission further finds:

(1) Socony Mobil Oil Company, Inc., is an independent producer of natural gas engaged in the sale of natural gas in interstate commerce for resale, subject to the jurisdiction of the Federal Power Commission and is, therefore, a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found.

(2) The sales of natural gas by Socony to Transcontinental Gas Pipe Line Corporation hereinbefore described, as more fully described in the application, are made in interstate commerce, subject to the jurisdiction of the Commission, and such sales, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) It is necessary and appropriate in the administration of the Natural Gas Act that the initial price charged by Socony for sales of gas produced from its

offshore High Island Block 10 reserves be 18 cents per Mcf at 14.65 psia rather than the 22.8 cents per Mcf provided by its contract of October 10, 1957, with Transco.

(4) Socony is able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act, and the requirements, rules and regulations of the Commission thereunder.

(5) The sales of natural gas by Socony, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

The Commission orders:

(A) Socony shall, within 60 days of the date of issuance of this order, refund to Transco with 6 percent interest a sum equal to the difference between 22.8 cents per Mcf at 15.025 psia and 18 cents per Mcf at 14.65 psia applied to all volumes delivered to Transco under Socony's FPC Gas Rate Schedule No. 198 from the date of initial delivery to Transco until the first billing date under this order.

(B) A certificate of public convenience and necessity is hereby issued to Socony authorizing the service and sale, proposed by it in its contract with Transco filed as its FPC Gas Rate Schedule No. 198.

(C) The certificate issued by paragraph (B), above, is hereby conditioned so that the total price effective under the aforesaid rate schedule, from the date of initial service thereunder, shall be 18 cents per Mcf at 14.65 psia.

(D) Within 10 days of the date of refund provided in paragraph (A), above, Socony shall file with the Commission an officially certified statement showing the amount of the refund, its manner of computation, and the interest payments related thereto.

(E) The certificate issued to Socony is not transferable and shall be effective only so long as it continues the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act, and the applicable rules, regulations, and orders of the Commission.

(F) The grant of a certificate to Socony herein is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against Socony.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

IDAHO POWER COMPANY, PROJECT NOS. 18 AND 503

ORDER DETERMINING AND DIRECTING ESTABLISHMENT AND MAINTENANCE OF AMORTIZATION RESERVES

(Issued February 13, 1962)

This is an amortization reserve proceeding pursuant to Section 10(d) of the Federal Power Act[1] involving two hydroelectric projects owned and operated

[1] Section 10(d) provides "[t]hat after the first twenty years of operation, out of surplus earned thereafter, if any, accumulated in excess of a specified reasonable rate of return upon the net investment of a licensee in any project or projects under license, the Licensee shall establish and maintain amortization reserves, which reserves shall, in the discretion of the Commission, be held until the termination of the license or be applied from time to time in reduction of the net investment. Such specified rate of return and the proportion of such surplus earnings to be paid into and held in such reserves shall be set forth in the license.

by the Idaho Power Company: licensed Project No. 18 (Twin Falls); licensed Project No. 503 (Swan Falls). It was initiated by the staff through a comprehensive field examination of the books, records and other data of the Licensee, Idaho Power Company.

Staff proposes that the Commission, pursuant to Section 10(d) of the Act and Articles 25 and 19 of the respective licenses for Project Nos. 18 and 503 determine: the amount of Licensee's "surplus earnings" from Project No. 18 for the period from December 3, 1955 through December 31, 1957, to be credited to Account 264, Amortization Reserve-Federal,[3] to be $1,424.20; and the amount of Licensee's "surplus earnings" from Project No. 503 for the period from January 1, 1948 through December 31, 1957, to be credited to Account 264 to be $8,125.64.

Articles 25 and 19 of the respective licenses for Project Nos. 18 and 503 provide as follows:

> After the first 20 years * * * of operation of the project under the license * * *, six * * * percent per annum shall be the specified rate of return on the net investment in the project for determining surplus earnings of the project for the establishment and maintenance of amortization reserves, pursuant to Section 10(d) of the Act; one-half of the project surplus earnings, if any, accumulated after the first twenty years of operation under the license, in excess of six * * * percent per annum on the net investment, shall be set aside in a project amortization reserve account as of the end of each fiscal year, provided that, if and to the extent that there is a deficiency of project earnings below six * * * percent per annum for any fiscal year or years after the first twenty years of operation under the license, the amount of such deficiency shall be deducted from the amount of any surplus earnings accumulated thereafter until absorbed, and one-half of the remaining surplus earnings, if any, thus cumulatively computed, shall be set aside in the project amortization reserve account; and the amounts thus established in the project amortization reserve account shall be maintained therein until further order of the Commission.

Licensee's Project No. 18 was placed in commercial operation on December 3, 1935, and therefore entered the amortization reserve period at the beginning of the twenty-first year of operation, December 3, 1955. Commercial operation of Project No. 503 commenced under license January 1, 1928, making the initial date of the amortization period for that project January 1, 1948. The licenses for both projects were issued pursuant to Section 4(d) of the Federal Water Power Act and are by their respective terms effective for the following periods: Project No. 18 for a period of 50 years commencing June 11, 1934; and Project No. 503 for a period effective January 1, 1928 and terminating June 30, 1970. Project No. 18 was unconstructed when licensed whereas Project No. 503 was in commercial operation when licensed.

Both projects are located within the State of Idaho and are physically operated by Licensee as an integral part of an interconnected system that includes other hydroelectric generating plants not under Commission license, internal combustion generation and a network of transmission and distribution systems. In addition, the Licensee received certain of its electric energy requirements by purchase from outside sources and also participates in power pool or interchange arrangments with other utility systems. The electric energy generated by both of the projects is intermingled and distributed in Licensee's system with energy

[3] Account references are to account numbers and titles prescribed in the Commission's revised Uniform System of Accounts for Public Utilities and Licensees effective January 1, 1961.

from its other sources of supply. Licensee's electric utility operations generally cover the areas of southern Idaho, eastern Oregon and northeastern Nevada. Licensee owns and operates facilities among others for the transmission and sale at wholesale of electric energy which is transmitted between the States of Idaho and Oregon, Idaho and Nevada, and Montana and Idaho, which energy is consumed at points outside of the States where generated.

Consistent with Licensee's method of physical operation of the above projects, its accounts, books and records do not show any particular earnings specifically associated therewith or derived therefrom. The same is true of Licensee's other generating or purchased power resources. In these circumstances, staff proposes that the Commission determine Licensee's respective "surplus earnings" from Project Nos. 18 and 503 as follows:

(1) Impute to the project during the respective fiscal periods concerned herein the particular earned rate of return which Licensee derived from its electric department utility operations as a whole during that period when computed in accordance with applicable precedents of this Commission;

(2) In the given fiscal period, determine the dollar excess, if any, of the project earnings, computed by applying the particular imputed earned rate of return to the average project net investment during the same period, over the project specified return, computed by applying the 6% specified rate of return to the average project net investment for the same period; such excess to be considered Licensee's "surplus earnings" during the particular period.

The following tabulations show the "surplus earnings" of the two projects during the amortization reserve periods covered by the staff's examination, computed in this manner, and the portions of such earnings to be credited to the respective amortization reserves for the two projects:

Project No. 18

Period	Surplus earnings over specified return and accumulated deficit		
	Surplus earnings	Accumulated deficit	Credits to Account 264
Dec. 3-31, 1955	($359.22)	($359.22)	
1956	(427.08)	(786.30)	
1957	3,634.70		$1,424.20
Total	2,848.40		1,424.20

Project No. 503

Period	Surplus earnings over specified return and accumulated deficit		
	Surplus earnings	Accumulated deficit	Credits to Account 264
1948	$16,138.70		$8,069.35
1949	112.58		56.29
1950	(4,634.13)	(34,634.13)	
1951	(8,322.62)	(12,956.75)	
1952	(5,067.63)	(18,624.38)	
1953	(4,874.75)	(23,499.13)	
1954	(5,076.56)	(28,575.69)	
1955	(4,351.46)	(32,927.15)	
1956	(592.18)	(33,519.33)	
1957	4,991.31	(28,528.02)	
Total	(12,276.74)	(28,528.02)	8,125.64

In developing Licensee's yearly actual earned rate of return, the staff derived rate base for the company's entire electric department operations for any given year is based upon average of beginning and end-of-year balances of electric plant in service (original cost), less related book depreciation reserves for electric plant in service, and less contributions in aid of construction, similarly averaged, plus an allowance for working capital; the last being computed on the basis of a cash allowance equal to one-eighth of cash operating expenses (exclusive of purchased power) for the particular year concerned plus average balances of materials and supplies and prepayments, less average available advance collections of Federal income taxes exclusive of accruals attributable to Federal taxes deferred.

Following this procedure, the staff also excluded for rate base purposes the balance in Licensee's Account 114, Electric Plant Acquisition Adjustments. In determining net electric department operating income, the staff excluded, as a revenue deduction, all annual charges for amortization of Licensee's investment classified in Account 114.

Staff treatment of Licensee's Federal income taxes reflects a normalization of the amounts of income taxes deferred by Licensee pursuant to Sections 167 and 168 of the Internal Revenue Code of 1954, in determining Licensee's net electric department operating income. Deferred State income taxes were treated in the same manner as deferred Federal income taxes.

Upon the conclusion of the staff examination, conferences were held between the staff and representatives of the Licensee at which agreement, subject to Commission approval, was reached as to the respective amounts of the "surplus earnings" of the two projects as well as the portions of such earnings to be credited to Licensee's Account 264 as indicated above. Licensee, by letter dated February 15, 1961, confirmed its agreement in the above matter and concurs that the Commission determine the amounts of "surplus earnings" to be credited to Account 264 as set forth above.

The Public Utilities Commission of Idaho was advised by letter of this Commission dated June 2, 1961, of the staff recommendations herein. That Commission on June 28, 1961, indicated its lack of objection to those recommendations.

As presented, the staff recommendations herein include the recommendation that any Commission determination of Licensee's "surplus earnings" as set forth above be made conditionally subject to revision in the event that certain charges by Electric Bond and Share Company and/or its affiliated service companies entered in Licensee's plant accounts during the years 1937 through 1957 and in Licensee's operating expense accounts during the period from January 1, 1948, through December 31, 1957, are determined hereafter to violate the Commission's "no profits to affiliates" rule. The staff analysis of Licensee's operations and earnings did not include a complete examination of the facts underlying the charges by Electric Bond and Share Company and/or its service company affiliates as to whether such charges include as a part thereof a profit element, or whether Electric Bond and Share Company and/or its service company affiliates and Licensee are associated companies within the meaning of the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees.

While the treatment herein of deferrals of income taxes conforms to our Uniform System of Accounts and certain prior Commission precedents and is accepted for the purposes of this determination of excess earnings, we do not necessarily endorse such treatment in principle and reserve the right to reexamine such treatment. We approve the instant determination for past periods inasmuch as any change in Commission policy would not be made retrospectively.

The Commission finds:

(1) The Federal Power Act [Section 10(d)] and more specifically Articles 25 and 19 of the respective licenses for Project Nos. 18 and 503 require that Licensee establish and maintain amortization reserves with respect to the above project wherein—

> one-half of the project surplus earnings, if any, accumulated after the first twenty years of operation under the license, in excess of six * * * percent per annum on the net investment, shall be set aside * * * in the project amortization reserve account; and the amounts thus established * * * shall be maintained therein until further order of the Commission.

(2) The first twenty years of operation of Project Nos. 18 and 503 under license ended as of December 2, 1955, and December 31, 1947, respectively.

(3) The computation of Licensee's respective "surplus earnings" from Project Nos. 18 and 503, subsequent to those dates, and the portions thereof to be credited to Account 264, in the manner as proposed by the staff all as described above, is reasonable and appropriate for the purposes of the Federal Power Act and the Commission licenses here concerned.

(4) For the periods commencing December 3, 1955 and January 1, 1948, both ending as of December 31, 1957, Licensee's respective surplus earnings for the above projects, on an annual basis, are as set forth in tabular form in the recitals above, as well as the portions thereof required to be set aside for the projects in Account 264, Amortization Reserve-Federal.

(5) As of December 31, 1957, the credit balances required to be maintained by Licensee in Account 264, Amortization Reserve-Federal, for the two projects are as follows: Project No. 18, $1,424.20; and Project No. 503, $8,125.64.

(6) Licensee's concurrence in the staff recommendations herein, and the lack of objection thereto by the Public Utilities Commission of Idaho, obviate the necessity for any public hearings in this matter prior to Commission action in accordance with those recommendations, as hereinafter provided.

(7) It is necessary and appropriate for the purposes of the Federal Power Act and the Commission licenses here concerned that the Commission reserve for future consideration the matter of revision of the respective amounts of Licensee's "surplus earnings" and the portions thereof required to be credited to Account 264 to reflect such adjustments therein as may be necessary: (a) if Licensee's payments to Electric Bond and Share Company, and/or the latter's service company affiliates, as described above are determined to include a profit element; and (b) if Licensee and Electric Bond and Share Company and/or the latter's service company affiliates are determined to be associated companies within the meaning of the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees.

The Commission orders:

(A) Licensee shall credit to Account 264, Amortization Reserve-Federal, by charge to Account 216, Unappropriated Earned Surplus, the amount of $1,424.20, for Project No. 18 for the period from December 3, 1955 through December 31, 1957; the amount of $8,125.64 for Project No. 503 for the period from January 1, 1948 through December 31, 1957; all as shown in the above tabulations.

(B) Licensee shall, within 60 days from the issuance of this order, file three certified copies of its journal entries recording the above credits.

(C) The respective amounts of Licensee's "surplus earnings" from Project Nos. 18 and 503 and the portions thereof required to be credited to Account 264 as determined herein, are expressly subject to revision as set forth in finding (7) above.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

MINNESOTA POWER & LIGHT COMPANY, PROJECT NOS 346 AND 469

ORDER DETERMINING AND DIRECTING ESTABLISHMENT AND MAINTENANCE OF AMORTIZATION RESERVES

(Issued February 13, 1962)

This is an amortization reserve proceeding pursuant to Section 10(d) of the Federal Power Act[1] involving two hydroelectric projects owned and operated by the Minnesota Power & Light Company: licensed Project No. 346; licensed Project No. 469. It was initiated by the staff through a comprehensive field examination of the books, records and other data of the Licensee, Minnesota Power & Light Company.

Staff proposes that the Commission, pursuant to Section 10(d) of the Act and Articles 19 and 18 of the respective licenses for Project Nos. 346 and 469, determine: the amount of Licensee's "surplus earnings" from Project No. 346 for the period from March 1, 1945 through December 31, 1956 to be credited to Account 264, Amortization Reserve-Federal,[2] to be $485,726.07; and the amount of Licensee's "surplus earnings" from Project No. 469 for the period from September 5, 1944 through December 31, 1956 to be credited to Account 264 to be $277,985.46.

Articles 19 and 18 of the respective licenses for Project Nos. 346 and 469 provide as follows:

> After the first 20 years of operation of said project under this license, out of surplus earnings * * * thereafter, if any, accumulated in excess of a specified reasonable rate of return upon the actual, legitimate investment of the Licensee in said project, all as defined in and determined by the provisions of Regulation 17 of said rules and regulations of the Commission, the Licensee shall establish and maintain amortization reserves, which reserves shall, in the discretion of the Commission, be held until the termination of the license or be applied from time to time in reduction of the net investment. Such specified rate of return shall * * * be one and one-half (1½) times the weighted average annual interest rate payable on the par value of the bona fide interest-bearing debt of the Licensee actually outstanding, in whole or in part, or account of the project property at the beginning of the period of amortization and of each calendar year thereafter; such weighted average annual interest rate being determined as provided in paragraphs B and C of Section 3 of said Regulation 17; *Provided*, That if at the beginning of the period of amortization or of any calendar year thereafter, the outstanding interest-bearing debt of the Licensee on account of the project or projects under license, together with any other works or property operated in connection therewith, is less than 25 percent

[1] Section 10(d) provides "[t]hat after the first twenty years of operation, out of surplus earned thereafter, if any, accumulated in excess of a specified reasonable rate of return upon the net investment of a licensee in any project or projects under license, the Licensee shall establish and maintain amortization reserves, which reserves shall, in the discretion of the Commission, be held until the termination of the license or be applied from time to time in reduction of the net investment. Such specified rate of return and the proportion of such surplus earnings to be paid into and held in such reserves shall be set forth in the license."

[2] Account references are to account numbers and titles prescribed in the Commission's revised Uniform System of Accounts for Public Utilities and Licensees effective January 1, 1961.

of the actual legitimate investment of the Licensee in said project or projects, then and in such event for the calendar year next following the specified rate of return shall be two (2) times the legal rate of interest in the State * * * of Minnesota.

Subject to the provisions of Section 6 of said regulation, the following proportions of such surplus earnings shall be paid into and held in such amortization reserves: of all surplus earnings up to and including 2 percent upon the actual, legitimate investment, 30 precent thereof shall be so paid; of all surplus earnings in excess of 2 percent and not in excess of 4 percent upon such investment, 50 percent thereof shall be so paid; of all surplus earnings in excess of 4 percent and not in excess of 6 percent, 70 percent thereof shall be so paid; and of all surplus earnings in excess of 6 percent 90 percent thereof shall be so paid; *Provided*, That if at the end of any calendar year of the amortization period the Commission shall find that the accumulated earnings of the Licensee during the period of operation, including the first twenty (20) years thereof, have not yielded a fair return upon the actual, legitimate investment in the project or projects under license, the proportion of such surplus earnings for such calendar year and for succeeding calendar years to be paid into such amortization reserves shall be ten (10) percent thereof until such time as the accumulated earnings of the Licensee represent, in the judgment of the Commission, a fair return upon such investment for such period of operation.

Licensee's Project No. 346 was placed in commercial operation on March 1, 1925 and therefore entered the amortization reserve period at the beginning of the twenty-first year of operation, March 1, 1945. Commercial operation of Project No. 469 commenced under license on September 5, 1924 making the initial date of the amortization period for that Project September 5, 1944. The licenses for both projects were issued pursuant to Section 4(d) of the Federal Water Power Act and are by their respective terms effective for the following periods: Project No. 346 for a period of 50 years commencing August 25, 1923; and Project No. 469 for a period terminating October 26, 1973. Project No. 346 was unconstructed when licensed, whereas Project No. 469 was in commercial operation when licensed.

Both projects are located within the State of Minnesota and are physically operated by the Licensee as an integral part of an interconnected system that includes other hydroelectric generating plants not under Commission license, steam production plants and a network of transmission and distribution systems. In addition, the Licensee receives certain of its electric energy requirements by purchase from other sources or through power pool or interchange arrangements with other companies. The electric energy generated by both of the projects is intermingled and distributed in Licensee's system with energy from its other sources of supply. Licensee operates in central and northeastern Minnesota.

Consistent with Licensee's method of physical operation of the above projects, its accounts, books and records do not show any particular earnings specifically associated therewith or derived therefrom. The same is true of Licensee's other generating or purchased power resources. In these circumstances, staff proposes that the Commission determine Licensee's respective "surplus earnings" from Project Nos. 346 and 469 as follows:

(1) Impute to the project during the respective fiscal periods concerned herein the particular earned rate of return which Licensee derived from its electric department utility operations as a whole during that period when computed in accordance with applicable precedents of this Commission;

(2) In the given fiscal period, determine the dollar excess, if any, of the project earnings, computed by applying the particular imputed earned rate of return to the average project net investment during the same period, over the project specified return, computed by applying the specified rate of return for the same period to the project net investment as of the beginning of the same period; such excess to be considered Licensee's "surplus earnings" during the particular period.

The following tabulation shows the "surplus earnings" of the two projects during the amortization reserve periods covered by the staff's examination, computed in this manner, and the portions of such earnings to be credited to the respective amortization reserves for the two projects:

Project No. 346

Period	Surplus earnings	Credits to Account 264	Period	Surplus earnings	Credits to Account 264
Mar. 1–Dec. 31, 1945	$117,136.06	$44,220.19	1952	$83,608.25	$32,512.54
1946	110,072.78	48,357.26	1953	76,748.63	29,151.03
1947	115,158.14	52,151.69	1954	52,760.86	17,022.66
1948	116,536.82	53,266.48	1955	62,113.74	21,764.65
1949	130,613.67	63,060.19	1956	62,516.97	22,105.54
1950	121,693.73	57,018.12	Total	1,153,491.56	485,726.07
1951	104,531.91	45,095.72			

Project No. 469

Period	Surplus earnings	Credits to Account 264	Period	Surplus earnings	Credits to Account 264
Sept. 5–Dec. 31, 1944	$36,973.88	$4,248.95	1952	$47,950.09	$18,864.91
1945	64,669.78	29,306.37	1953	43,019.31	16,248.56
1946	60,842.41	26,750.33	1954	29,516.81	9,496.33
1947	63,507.26	28,723.69	1955	35,283.39	12,433.67
1948	63,677.06	28,964.13	1956	35,516.62	12,578.17
1949	71,276.35	34,400.60			
1950	66,259.94	31,012.30	Total	675,981.57	277,985.46
1951	57,488.67	24,957.45			

In developing Licensee's yearly actual earned rate of return, the staff derived rate base for the Company's entire electric department operations for any given year is based upon average of beginning and end-of-year balances of electric plant in service (original cost), less related book depreciation reserves and amortization of limited-term electric investments, and less contributions in aid of construction, similarly averaged, plus an allowance for working capital; the last being computed on the basis of a cash allowance equal to one-eighth of cash operating expenses (exclusive of purchased power expense) for the particular year concerned plus average balances of materials and supplies and prepayments less average available advance collections of Federal income taxes exclusive of accruals attributable to Federal taxes deferred.

Following this procedure, the staff excluded for rate base purposes the balance in Licensee's Account 114, Electric Plant Acquisition Adjustments. In determining net electric department operating income, the staff excluded, as a revenue deduction, all annual charges for amortization of Licensee's investment classified in Account 114.

Staff treatment of Licensee's Federal income taxes reflects a normalization of the amount of income taxes deferred by Licensee pursuant to Section 168 of the Internal Revenue Code of 1954, in determining Licensee's net electric depart-

ment operating income. Deferred State income taxes were treated in the same manner as deferred Federal income taxes.

Upon the conclusion of the staff examination, conferences were held between the staff and representatives of the Licensee at which agreement, subject to Commission approval, was reached as to the respective amounts of the "surplus earnings" of the two projects, as well as the portions of such earnings to be credited to Licensee's Account 264, as indicated above.

Licensee, by letter dated September 23, 1960, confirmed its agreement in the above matter and concurs that the Commission determine the amounts of "surplus earnings" to be credited to Account 264, as set forth above.

As presented, the staff recommendations herein include the recommendation that any Commission determination of Licensee's "surplus earnings" as set forth above be made conditionally subject to revision in the event that certain charges by Electric Bond and Share Company and/or its affiliated service companies entered in Licensee's Plant accounts during the years 1937 through 1956 and in Licensee's operating expense accounts during the period from September 5, 1944 through December 31, 1956 are determined hereafter to violate the Commission's "no profits to affiliates" rule. The staff analysis of Licensee's operations and earnings did not include a complete examination of the facts underlying the charges by Electric Bond and Share Company and/or its service company affiliates, as to whether such payments include as a part thereof a profit element or whether Electric Bond and Share Company and/or its service company affiliates and Licensee are associated companies within the meaning of the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees.

While the treatment herein of deferrals of income taxes conforms to our Uniform System of Accounts and certain prior Commission precedents and is accepted for the purposes of this determination of excess earnings, we do not necessarily endorse such treatment in principle and reserve the right to reexamine such treatment. We approve the instant determination for past periods inasmuch as any change in Commission policy would not be made retrospectively.

The Commission finds:

(1) The Federal Power Act [Section 10(d)] and Articles 19 and 18 of the respective licenses for Project Nos. 346 and 469 require that Licensee establish and maintain amortization reserves with respect to those projects wherein:

> Subject to the provisions of Section 6 of said regulation, the following proportions of such surplus earnings shall be paid into and held in such amortization reserves: Of all surplus earnings up to and including 2 percent upon the actual, legitimate investment, 30 percent thereof shall be so paid; of all surplus earnings in excess of 2 percent and not in excess of 4 percent upon such investment, 50 percent thereof shall be so paid; of all surplus earnings in excess of 4 percent and not in excess of 6 percent, 70 percent thereof shall be so paid; and of all surplus earnings in excess of 6 percent, 90 percent thereof shall be so paid; *Provided*, That if at the end of any calendar year of the amortization period the Commission shall find that the accumulated earnings of the Licensee during the period of operation, including the first twenty (20) years thereof, have not yielded a fair return upon the actual, legitimate investment in the project or projects under license, the proportion of such surplus earnings for such calendar year and for succeeding calendar years to be paid into such amortization reserves shall be ten (10) percent thereof until such time as the accumulated earnings of the Licensee represent, in the judgment of the Commission, a fair return upon such investment for such period of operation.

(2) The first 20 years of operation of Project Nos. 346 and 469 under license ended as of February 28, 1945 and September 4, 1944, respectively.

(3) The computation of Licensee's respective "surplus earnings" from Project Nos. 346 and 469, subsequent to those dates and the portions thereof to be credited to Account 264, in the manner as proposed by the staff, all as described above, is reasonable and appropriate for the purposes of the Federal Power Act and the Commission licenses here concerned.

(4) For the periods commencing March 1, 1945 and September 5, 1944, both ending as of December 31, 1956, Licensee's respective "surplus earnings" for the above projects, on an annual basis, are as set forth in tabular form in the recitals above, as well as portions thereof required to be set aside for the projects in Account 264, Amortization Reserve-Federal.

(5) As of December 31, 1956, the credit balances required to be maintained by Licensee in Account 264, Amortization Reserve-Federal for the two projects, are as follows: Project No. 346—$485,726.07; and Project No. 469—$277,985.46.

(6) Licensee's concurrence in the staff recommendations herein, obviates the necessity for any public hearings in this matter prior to Commission action in accordance with those recommendations, as hereinafter provided.

(7) It is necessary and appropriate for the purposes of the Federal Power Act and the Commission licenses here concerned that the Commission reserve for future consideration the matter of revision of the respective amounts of Licensee's "surplus earnings" and the portions thereof required to be credited to Account 264, to reflect such adjustments therein as may be necessary: (a) if Licensee's payments to Electric Bond and Share Company and/or the latter's service company affiliates as described above are determined to include a profit element; and (b) if Licensee and Electric Bond and Share Company and/or the latter's service company affiliates are determined to be associated companies within the meaning of the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees.

The Commission orders:

(A) Licensee shall credit to Account 264, Amortization Reserve-Federal, by charge to Account 216, Unappropriated Earned Surplus, the amount of $485,726.07 for Project No. 346 for the period from March 1, 1945 through December 31, 1956; the amount of $277,985.46 for the period from September 5, 1944 through December 31, 1956; all as shown in the above tabulations.

(B) Licensee shall, within 60 days from the issuance of this order, file three certified copies of its journals entries recording the above credits.

(C) The respective amounts of Licensee's "surplus earnings" from Project Nos. 346 and 469 and the portions thereof required to be credited to Account 264 as determined herein, are expressly subject to revision as set forth in finding (7) above.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SHELL OIL COMPANY, DOCKET NO. G–13876

ORDER REQUIRING ADDITIONAL REFUND

(Issued February 13, 1962)*

By order issued February 23, 1960, in El Paso Natural Gas Company, *et al.*, Docket Nos. G–13862, *et al.* (23 FPC 369, 380), the Commission issued to Shell

*Rehearing denied; stay granted by order issued April 6, 1962, 27 FPC 674.

Oil Company, Docket No. G–13876, a certificate of public convenience and necessity authorizing the sale by Shell to El Paso of natural gas to be produced in certain fields in the Aneth area in San Juan County, Utah, at the rate of 17.7¢ per Mcf. The Commission ordered that Shell file a supplement to its FPC Gas Rate Schedule No. 178 providing for the rate of 17.7¢ per Mcf in lieu of the initial price of 20¢ contained in Shell's contract with El Paso, and that Shell refund to El Paso amounts collected from El Paso pursuant to the temporary authorization issued to Shell on November 18, 1958, in excess of the amounts which would have been collected under the certificate rate, with interest at the rate of 6% per year.

While the temporary authorization was in effect the State of Utah increased its occupation tax from 1% to 2%, effective January 1, 1960. Pursuant to the terms of its contract concerning additional taxes, Shell submitted on May 18, 1960, a notice of rate change reflecting full reimbursement of the 1% tax increase applied to its 20¢ contract rate. That tax increase, amounting to approximately 0.2¢ per Mcf, was accepted by our letter order dated July 10, 1960, which specified that the acceptance was subject to Shell's agreement to the refund conditions of the temporary authorization issued November 18, 1958.

On October 30, 1961, Shell submitted the required supplement to its Rate Schedule No. 178, and by letter dated December 5, 1961, it reported that on November 7, 1961, it refunded to El Paso, pursuant to the Commission's Opinion and Order No. 335, a total of $176,786.01, which sum included interest in the amount of $13,677.42. Details of the computation of the amount refunded were given in Shell's letter to the Commission dated November 2, 1961.

The sum of $176,786.01 refunded to El Paso did not include the tax reimbursement which Shell had collected from El Paso and which, during the period commencing May 18, 1960 (effective date of the 0.2¢ tax filing), and ending November 7, 1961 (date of refund to El Paso), amounted to approximately $7,500.

The Commission finds:

Shell Oil Company should refund to El Paso Natural Gas Company all amounts which it has collected from El Paso, including said tax reimbursement, in excess of the amounts resulting from the 17.7¢ per Mcf rate authorized by us as aforesaid under Docket No. G–13876, and Shell's supplement to its FPC Gas Rate Schedule No. 178 should be modified accordingly.

The Commission orders:

(A) Shell Oil Company shall refund to El Paso Natural Gas Company within 90 days after the date of this order all amounts collected from El Paso in excess of the amounts which would have been collected under the rate at which Shell's sales were certified in our aforesaid order issued February 23, 1960 (23 FPC 380), and in excess also of amounts previously refunded by Shell to El Paso pursuant to said order, with interest at the rate of 6% per year computed from the date of the collection of said amounts to the date of refund, and shall report to the Commission, in writing and under oath, the details of such refund within 15 days after it is made.

(B) Shell shall file with the Commission, within 30 days after the date of this order, a supplement to its FPC Gas Rate Schedule No. 178 reflecting compliance with the Commission's said order issued February 23, 1960.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SOUTHERN CALIFORNIA EDISON COMPANY, PROJECT NOS. 67, 120 AND 382

ORDER DETERMINING AND DIRECTING ESTABLISHMENT AND MAINTENANCE OF AMORTIZATION RESERVES

(Issued February 13, 1962)

This is an amortization reserve proceeding pursuant to Section 10(d) of the Federal Power Act[1] involving three hydroelectric projects owned and operated by Southern California Edison Company; licensed Project No. 67 (Big Creek-Part); licensed Project No. 120 (Big Creek-Part); and licensed Project No. 382 (Borel). It was initiated by the staff through a comprehensive field examination of the books, records and other data of the Licensee, Southern California Edison Company.

Staff proposes that the Commission, pursuant to Section 10(d) of the Act and Articles 10, 18 and 20 of the respective afore-mentioned project licenses determine: the amount of Licensee's "surplus earnings" from Project No. 67 for the period from June 1, 1941, through December 31, 1955, to be credited to Account 264, Amortization Reserve-Federal,[2] to be $88,124.52; the amount of Licensee's "surplus earnings" from Project No. 120 for the period from October 1, 1943 through December 31, 1955 to be credited to Account 264, to be $59,834.52; and the amount of Licensee's "surplus earnings" from Project No. 382 for the period from March 1, 1945 through December 31, 1955 to be credited to Account 264 to be $7,715.64.

Articles 10, 18 and 20 of the licenses for Project Nos. 67, 120 and 382, respectively, provide as follows:

> After the first twenty (20) years of operation of the project under the license, six (6) percent per annum shall be the specified rate of return on the net investment in the project for determining surplus earnings of the project for the establishment and maintenance of amortization reserves, pursuant to Section 10(d) of the Act, one-half of the project surplus earnings, if any, accumulated after the first twenty years of operation under the license, in excess of six (6) percent per annum on the net investment shall be set aside in a project amortization reserve account as of the end of each fiscal year, provided that, if and to the extent that there is a deficiency of project earnings below six (6) percent per annum for any fiscal year or years after the first twenty years of operation under the license, the amount of such deficiency shall be deducted from the amount of any surplus earnings accumulated thereafter until absorbed,

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[1] Section 10(d) provides "[t]hat after the first twenty years of operation, out of surplus earned thereafter, if any, accumulated in excess of a specified reasonable rate of return upon the net investment of a licensee in any project or projects under license, the Licensee shall establish and maintain amortization reserves, which reserves shall, in the discretion of the Commission, be held until the termination of the license or be applied from time to time in reduction of the net investment. Such specified rate of return and the proportion of such surplus earnings to be paid into and held in such reserves shall be set forth in the license."

[2] Account references are to account numbers and titles prescribed in the Commission's revised Uniform System of Accounts for Public Utilities and Licensees effective January 1, 1961.

and one-half of the remaining surplus earnings, if any, thus cumulatively computed, shall be set aside in the project amortization reserve account, and the amounts thus established in the project amortization reserve account shall be maintained therein until further order of the Commission.

Licensee's Project No. 67 was placed in commercial operation on June 1, 1921, and, therefore, entered the amortization reserve period at the beginning of the twenty-first year of operation, June 1, 1941. Project No. 120 was placed in commercial operation on October 1, 1923 and entered its amortization reserve period October 1, 1943. Commercial operation of Project No. 382 commenced under license March 1, 1925 making the initial date of the amortization period for that project March 1, 1945. The licenses for all three projects were issued pursuant to Section 4(d) of the Federal Water Power Act and are by their respective terms each effective for a period of fifty years (except Project No. 120, the term of which ends March 3, 1971) from the following effective dates: Project No. 67, March 3, 1921; Project No. 120, June 8, 1922; and Project No. 382, February 28, 1925.[2]

All of the projects are located within the State of California and are physically operated by Licensee, as an integral part of an interconnected system that includes other hydroelectric generating plants not under Commission license, steam production plants and a network of transmission and distribution systems. In addition, Licensee receives certain of its electric energy requirements by purchase from outside sources and also participates in power pool or interchange arrangements with other utility systems including federal and state agencies or authorities. The electric energy generated by each of the three projects is intermingled and distributed in Licensee's system with energy from its other sources of supply. Licensee's electric utility operations generally cover Central and Southern California. In addition Licensee's electric facilities are located in or interconnect with facilities of others located in one or more of the States of Arizona, California or Nevada.

Consistent with Licensee's method of physical operation of the above projects, its accounts, books and records do not show any particular earnings specifically associated therewith or derived therefrom. The same is true of Licensee's other generating or purchased power resources. In these circumstances, staff proposes that the Commission determine Licensee's respective "surplus earnings" from Project Nos. 67, 120 and 382 as follows:

(1) Impute to the project during the respective fiscal periods concerned herein the particular earned rate of return which Licensee derived from its electric department utility operations as a whole during that period when computed in accordance with applicable precedents of this Commission;

(2) In the given fiscal period, determine the dollar excess, if any, of the project earnings, computed by applying the particular imputed earned rate of return to the average project net investment during the same period, over the project specified return, computed by applying the 6% specified rate of return to the average project net investment for the same period; such excess to be considered Licensee's "surplus earnings" during the particular period.

The following tabulations show the "surplus earnings" of the three projects during the amortization reserve periods covered by the staff's examination computed in this manner, and the portions of such earnings to be credited to the respective amortization reserves for the three projects:

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[2] Project No. 382 was constructed and in commercial operation when licensed.

Project No. 67

Period	Surplus earnings over specified return and accumulated deficit		
	Surplus earnings	Accumulated deficit [1]	Credits to Account 264
June 1–Dec. 31, 1941	$31,049.71		$15,524.86
1942	30,909.22		15,454.61
1943	(230,795.96)	($230,795.96)	
1944	(20,422.30)	(251,218.26)	
1945	(20,371.74)	(271,590.00)	
1946	385,880.10		57,145.05
1947	(1,971,621.52)	(1,971,621.52)	
1948	(1,047,108.84)	(3,018,730.36)	
1949	190,775.08	(2,827,955.28)	
1950	55,349.84	(2,772,605.44)	
1951	(180,034.92)	(2,952,640.36)	
1952	193,601.40	(2,759,038.96)	
1953	(295,389.14)	(3,054,428.10)	
1954	(170,421.39)	(3,224,849.49)	
1955	(182,409.90)	(3,407,259.39)	
Total	(3,231,010.36)	(3,407,259.39)	88,124.52

[1] The deficiency in earnings occurring mainly in the years 1947 and 1948 reflects large expenditures by Licensee in converting portions of its electric system from 50 to 60 cycle operation. The major portion of such cost was expensed by Licensee.

Project No. 120

Period	Surplus earnings over specified return and accumulated deficit		
	Surplus earnings	Accumulated deficit	Credits to Account 264
Oct. 1–Dec. 31, 1943	($21,311.85)	($21,311.85)	
1944	(8,474.11)	(29,785.96)	
1945	(8,396.85)	(38,182.81)	
1946	157,851.85		$59,834.52
1947	(801,077.59)	(801,077.59)	
1948	(444,210.51)	(1,245,288.10)	
1949	84,713.78	(1,160,574.32)	
1950	24,700.12	(1,135,874.20)	
1951	(80,584.97)	(1,216,459.17)	
1952	(86,329.82)	(1,130,129.35)	
1953	(133,863.16)	(1,263,992.51)	
1954	(78,458.19)	(1,342,450.70)	
1955	(83,575.66)	(1,426,026.36)	
Total	(1,306,357.32)	(1,426,026.36)	59,834.52

Project No. 382

Period	Surplus earnings over specified return and accumulated deficit		
	Surplus earnings	Accumulated deficit	Credits to Account 264
Mar. 1–Dec. 31/45	($645.76)	($645.76)	
1946	16,077.03		$7,715.64
1947	(81,066.34)	(81,066.34)	
1948	(42,327.95)	(123,394.29)	
1949	7,536.39	(115,857.90)	
1950	2,154.65	(113,703.25)	
1951	(6,929.34)	(120,632.59)	
1952	7,307.69	(113,324.90)	
1953	(10,947.31)	(124,272.21)	
1954	(6,206.93)	(130,479.14)	
1955	(6,545.27)	(137,024.41)	
Total	(121,593.14)	(137,024.41)	7,715.64

In developing Licensee's yearly actual earned rate of return, the staff derived rate base for the company's entire electric department operations for any given year is based upon average of beginning and end-of-year balances of electric plant in service (original cost), less related book depreciation reserves, less customers' advances for construction, and less contributions in aid of construction, similarly averaged, plus an allowance for working capital; the last being computed on the basis of a cash allowance equal to one-eighth of cash operating expenses (exclusive of purchased power and fuel expenses associated with the operation of Licensee's thermal electric generating resources) for the particular year concerned plus average balances of materials and supplies and prepayments, less average available advance collections of Federal income taxes exclusive of accruals attributable to Federal taxes deferred.

Following this procedure, the staff also excluded for rate base purposes the balance in Licensee's Account 114, Electric Plant Acquisition Adjustments. In determining net electric department operating income, the staff excluded, as a revenue deduction, all annual charges for amortization of Licensee's investment classified in Account 114.

Staff treatment of Licensee's Federal income taxes reflects a normalization of the amounts of income taxes deferred by Licensee pursuant to Sections 167 and 168 of the Internal Revenue Code of 1954, in determining Licensee's net electric department operating income. Deferred State income taxes were treated in the same manner as deferred Federal income taxes.

Upon the conclusion of the staff examination, conferences were held between the staff and representatives of the Licensee at which agreement, subject to Commission approval, was reached as to the respective amounts of the "surplus earnings" of the three projects, as well as the portions of such earnings to be credited to Licensee's Account 264 as indicated above. Licensee, by letter dated October 5, 1960, confirmed its agreement in the above matter and concurs that the Commission determine the amount of "surplus earnings" to be credited to account 264, as set forth above.

The Public Utilities Commission of California was advised by letter of this Commission dated May 16, 1961, of the staff recommendations herein. That Commission by letter dated June 2, 1961 indicated its lack of objection to those recommendations.

While the treatment herein of deferrals of income taxes conforms to our Uniform System of Accounts and certain prior Commission precedents and is accepted for the purposes of this determination of excess earnings, we do not necessarily endorse such treatment in principle and reserve the right to re-examine such treatment. We approve the instant determination for past periods inasmuch as any change in Commission policy would not be made retrospectively.

The Commission finds:

(1) The Federal Power Act [Section 10(d)] and more specifically Articles 10, 18 and 20 of the respective licenses for project Nos. 67, 120 and 382 require that Licensee establish and maintain amortization reserves with respect to those projects wherein—

> one-half of the project surplus earnings, if any, accumulated after the first twenty years of operation under the license, in excess of six (6) percent per annum on the net investment, shall be set aside * * * in the project amortization reserve account; and the amounts thus established * * * shall be maintained therein until further order of the Commission.

(2) The first twenty years of operation of Project Nos. 67, 120 and 382 under license ended as of May 31, 1941, September 30, 1943 and February 18, 1945, respectively.

(3) The computation of Licensee's respective "surplus earnings" from Project Nos. 67, 120 and 382 subsequent to those dates, and the portions thereof to be credited to Account 264, in the manner as proposed by the staff, all as described above, is reasonable and appropriate for the purposes of the Federal Power Act and the Commission licenses here concerned.

(4) For the periods commencing June 1, 1941, October 1, 1943 and March 1, 1945, all ending as of December 31, 1955, Licensee's respective "surplus earnings" for the above projects, on an annual basis, are in tabular form in the recitals above, as well as the portions thereof required to be set aside for the project in Account 264, Amortization Reserve-Federal.

(5) As of December 31, 1955, the credit balances required to be maintained by Licensee in Account 264, Amortization Reserve-Federal for the three projects are as follows: Project No. 67—$88,124.52; Project No. 120—$59,834.52; and Project No. 382—$7,715.64.

(6) Licensee's concurrence in the staff recommendations herein, and the lack of objection thereto by the Public Utilities Commission of California, obviate the necessity for any public hearings in this matter prior to Commission action in accordance with those recommendations, as hereinafter provided.

The Commission orders:

(A) Licensee shall credit to Account 264, Amortization Reserve-Federal, by charge to Account 216, Unappropriated Earned Surplus, the amount of $88,124.52, for Project No. 67 for the period from June 1, 1941 through December 31, 1955; the amount of $59,834.52 for Project No. 120 for the period from October 1, 1943 through December 31, 1955; the amount of $7,715.64 for Project No. 382 for the period from March 1, 1945 through December 31, 1955; all as shown in the above tabulations.

(B) Licensee shall, within 60 days from the issuance of this order, file three certified copies of its journal entries recording the above credits.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SOUTHERN CALIFORNIA EDISON COMPANY, PROJECT NO. 372

ORDER FURTHER AMENDING LICENSE (MAJOR)

(Issued February 13, 1962)

Application was filed September 29, 1961 by Southern California Edison Company, licensee for major Project No. 372, for further amendment of the license for the project located on Middle Fork of Tule River in Tulare County, California, and affecting lands of the United States within Sequoia National Forest.

The application states that the flumes and ditches of the conduit between a point in the NW¼SW¼ of Section 28 and a point in the SE¼SW¼ of Section 29, T. 20 S., R. 30 E., M.D.B. & M. have been replaced with two relocated 30 inch diameter welded steel pipes, and the ditches and flumes have been abandoned and removed. Relocation of the section of conduit reduced the area of government lands occupied by the project by 13.37 acres, and the amount of annual charges for the occupancy of such lands should be reduced accordingly.

On July 9, 1960, approximately 5,000 feet of flume were rendered useless by fire. Replacement of the flumes and ditches with the double siphon was the quickest and most economical way in which the project plant could be put back into service.

The Chief, Forest Service, acting for the Secretary of Agriculture, who has supervision over the Sequoia National Forest, in reporting on the application, has advised that the destroyed and abandoned flumes have been removed and the right-of-way restored to a condition satisfactory to the Service, and no special conditions for the protection and utilization of National Forest lands are necessary other than those already in the license.

Although invited, no comments on the application have been received from any agency of the State of California.

The Commission finds:

(1) The license, further amended as hereinafter ordered, will not interfere or be inconsistent with the purposes for which the Sequoia National Forest was created or acquired and is in the public interest.

(2) Public notice has been given of the filing of the application. No protests have been received.

(3) The following described exhibits filed as a part of the application for amendment conform to the Commission's rules and regulations and should be approved as part of the license for the project, and the exhibits which they supersede and which are now part of the license should be eliminated therefrom to the extent indicated—all as hereinafter provided:

Exhibit J: (FPC No. 372–46), superseding *Exhibit J:* (FPC No. 372–40);

Exhibit K: (FPC No. 372–47), superseding *Exhibit K:* (FPC No. 372–17);

Exhibit K: (FPC No. 372–48), superseding *Exhibit K:* (FPC No. 372–18); and

Exhibit L: (FPC No. 372–49), superseding *Exhibit K:* Sheets 6 and 7 (FPC No. 372–21 and –22), insofar as they show the profile of the conduit from Station 241+67.64 to Station 173+60.04.

The Commission orders:

(A) The exhibits described in finding (3) above as conforming to the Commission's rules and regulations are approved as part of the license for Project No. 372 and the exhibits described in the same finding as being superseded are eliminated from the license for the project to the extent therein indicated.

(B) The license for Project No. 372 is further amended, effective as of January 1, 1962, as follows:

PARAGRAPH I. Article 2 of the license is amended by substituting in subparagraph C thereof the figure "32,122.8" for the figure "34,856" appearing in line 8 therein.

PARAGRAPH II. Article 19 of the license is amended by revising subparagraph B thereof to read as follows:

B. For the purpose of recompensing the United States for the use, occupancy, and enjoyment of its lands within the project area, $217.16.

(C) This amendment in the manner set out above shall not operate to alter or amend the license in any other respect, and shall not in anyway constitute a waiver of any other part, provision or condition of the license as heretofore amended.

(D) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313(a) of the Federal Power Act and failure to file such an application shall constitute acceptance of this amendment of license. In acknowledgment of the acceptance of this amendment of license, it shall be signed for the licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

PACIFIC POWER & LIGHT COMPANY, DOCKET NO. E-7020

ORDER AUTHORIZING ISSUANCE OF COMMON STOCK

(Issued February 16, 1962)

Pacific Power & Light Company (Applicant), a corporation organized under the laws of the State of Maine and doing business in the States of California, Oregon, Washington, Wyoming, Montana and Idaho, with its principal business office at Portland, Oregon, filed an application on December 28, 1961, as amended January 24, 1962, for authority, pursuant to Section 204 of the Federal Power Act, to issue not to exceed 6,981,361 shares of Common Stock, par value $3.25 per share, for a reclassification, or split, of the outstanding Common Stock of Applicant.

Applicant's Common Stockholders, at a special meeting on February 7, 1962, amended Applicant's Certificate of Organization and By-Laws to increase and change the Common Stock which it is authorized to issue from 8,212,679 shares of par value $6.50 per share to 16,425,358 shares of par value $3.25 per share, and to split and change the number of shares of its outstanding Common Stock of the par value of $6.50 per share into twice such number of shares of Common Stock of the par value of $3.25 per share.

After the effective date of the amendments, the outstanding certificates of the present $6.50 par value Common Stock will be treated as evidencing and will automatically represent the same number of shares of new $3.25 par value Common Stock. As promptly as possible after such effective date, all holders of Common Stock of record at the close of business on such date will be sent certificates for the additional shares of $3.25 par value stock to which they will be entitled as a result of the two-for-one split. Common Stockholders will then have, together with the certificates which they retain, two shares of $3.25 par value stock for each share of $6.50 par value stock held before the split. The aggregate capital represented by Applicant's Common Stock will not be changed as a result of the proposed transaction.

Applicant states that the purpose of the proposed reclassification of its Common Stock is to establish the price per share of such Common Stock at a market value level which will more readily attract new investors and broaden the public interest in the Common Stock of Applicant.

Written notice of the application has been given to the Public Utilities Commission of California, the Public Utilities Commission of Idaho, the Board of Railroad Commissioners of Montana, the Utilities and Transportation Commission of Washington, the Public Service Commission of Wyoming, the Public Utility Commissioner of Oregon, and to the Governors of each of those States. Notice has also been given by publication in the Federal Register on January 13, 1962 (27 F.R. 432), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before January 29, 1962 with the Federal Power Commission, Washington 25, D.C. No protest, petition or request to be heard in opposition to the granting of the application has been received.

The Public Utilities Commission of California, by order dated January 23, 1962, and the Public Utilities Commission of Idaho, by order dated January 24, 1962, authorized Applicant to double the number of shares of its Common Stock authorized and outstanding and to change the par value thereof from $6.50 to $3.25 per share, as described above. The Public Service Commission of Wyoming,

by letter dated January 11, 1962, and the Board of Railroad Commissioners of Montana, by minute entry dated January 22, 1962, advised Applicant that the proposed stock split is not subject to their jurisdiction.

The Commission finds:

(1) Applicant, a corporation, is a public utility within the meaning of Section 204 of the Federal Power Act subject to the jurisdiction of the Commission as heretofore determined and set forth in the Commission's order issued April 24, 1958, *In the Matters of The California Oregon Power Company and Pacific Power & Light Company*, 19 FPC 573.

(2) The proposed issuance of Common Stock, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204(f) of the Act, and the proposed issuance of Common Stock, as described above, is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance of Common Stock, as described above, is exempt from the competitive bidding requirements of Section 34.1a of the Commission's Regulations under the Federal Power Act by reason of Paragraph 34.1a(a)(1) thereof.

(5) The proposed issuance of Common Stock, as hereinafter authorized, will be for a lawful object, within the corporate purposes of Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The proposed issuance of Common Stock, as described above, upon the terms and conditions and for the purposes specified in the application, is hereby authorized, subject to the provisions of this order.

(B) This authorization shall expire unless the transaction hereby authorized is consummated within 60 days from the date of issuance of this order.

(C) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuations, estimates or determinations of costs, or any other matter whatsoever which is now pending or which hereafter may come before this Commission or any other regulatory body.

(D) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States in respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NOS. G–20388, G–20389, AND G–1922

ORDER DENYING APPLICATION FOR REHEARING

(Issued February 14, 1962)

On January 15, 1962, Fuels Research Council, Inc., National Coal Association, United Mine Workers of America, and Anthracite Institute (Applicants) timely

filed a joint application for rehearing of the Commission's Opinion No. 349 and accompanying order issued December 14, 1961, (a) granting Tennessee Gas Transmission Company (Tennessee) a certificate of public convenience and necessity under Section 7(c) of the Natural Gas Act (Act) to receive, transport and sell certain volumes of natural gas to be purchased on an interruptible basis from Trans-Canada Pipe Lines Ltd., (b) granting Tennessee authority under Section 3 of the Act to import said gas, and (c) amending Tennessee's Presidential Permit pursuant to Executive Order 10485 to allow the use of the existing border facilities for the importation, all as more fully set forth in the opinion.

Contending that the actions are contrary to law and unsupported by facts, Applicants request that we grant rehearing, that Opinion No. 349 and accompanying order be declared of no force and effect, and in lieu thereof that we affirm the examiner's decisions of September 2, 1960 and June 20, 1961, denying Tennessee's applications.

We have considered the assignments of error and grounds for rehearing set forth in the application for rehearing, described above, and have reconsidered our Opinion No. 349. The arguments advanced here by Applicants are essentially the same as those advanced in their briefs to the examiner and rejected by us in the opinion. No new facts or arguments are called to our attention which would be cause for granting rehearing or disturbing the original opinion and order.

There is, however, one matter we desire to discuss briefly here. In their discussion of why market data is a prerequisite to the issuance of Tennessee's requested certificate, Applicants contend that by not requiring Tennessee to submit market data demonstrating the exact disposition of the imported gas no determination can be made as to the effect, if any, the importation would have on coal markets. Their argument is that the gas could be sold to new markets and, consequently deprive coal of markets. For example, they allege that Tennessee could sell the gas on an interruptible basis to existing customers who in turn could sell the gas to new consumers who might not otherwise obtain any service because of the lack of available gas during the summer or other off-peak periods.

This argument is not well-grounded. Tennessee received no certificate authority to increase sales to existing customers or to institute service to new customers. Tennessee's sales to its present customers are limited by terms of contracts which are necessarily incorporated in certificates, and should Tennessee desire to increase its sales above certificate levels, additional certificate authority would be necessary. Within the limits of existing authorizations Tennessee's customers always could take excess gas, but there is no showing that all gas available in off-peak periods ever was taken or that more will be taken when Canadian gas rather than Southwest gas is offered.

The Commission finds:

The assignments of error and grounds for rehearing set forth in the above-described application for rehearing present no facts or principles of law which were not considered by the Commission when it issued its Opinion No. 349 and accompanying order on December 14, 1961, or which having now been considered warrant any change or modification of said opinion and order.

The Commission orders:

The application for rehearing filed by the Applicants on January 15, 1962, is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

ATLANTIC SEABOARD CORPORATION, DOCKET NO. G-20272

ORDER GRANTING IN PART PETITION FOR RECONSIDERATION AND MODIFYING ORDER CONDITIONALLY APPROVING RATE SETTLEMENT AGREEMENT

(Issued February 19, 1962)

On January 15, 1962, Atlantic Seaboard Corporation (Atlantic Seaboard) filed a petition for reconsideration of our order issued December 29, 1961, 26 FPC 945, conditionally approving a rate settlement agreement and providing for a limited hearing in the above proceeding.

The settlement agreement provided, among other things, for stipulated rate reductions and refunds from April 5, 1960, in the event that Atlantic Seaboard's Boldman Compressor Station were transferred to United Fuel Gas Company (United Fuel), an affiliate in the Columbia Gas System, Inc. We conditioned our approval of the settlement agreement to require Atlantic Seaboard also to file revisions in rates and proposals for refunds appropriate to other transfers by Atlantic Seaboard.[1]

In its petition for reconsideration, Atlantic Seaboard requests deletion of said requirement concerning facilities other than Boldman Compressor Station. Atlantic Seaboard states that the settlement provision for refunds upon the transfer of Boldman Station is correlated with a provision in another rate settlement agreement between United Fuel and others in the proceeding in Docket No. G-20270. The United Fuel Settlement is based on a cost of service which includes the cost of Atlantic Seaboard's Boldman Station and further provides that in the event certificate authority for the transfer of Boldman Station to United Fuel is not granted, then United Fuel will make stipulated rate reductions and refunds from April 5, 1960. Thus under the correlated settlement agreements, either United Fuel or Atlantic Seaboard will include the Boldman Station in its rate base from April 5, 1960, and the other will make related refunds. The United Fuel settlement, however, is not based upon a cost of service which also includes the cost of other facilities that may be transferred to it by Atlantic Seaboard under the above referenced certificate proceeding. Therefore, if Atlantic Seaboard makes refunds incident to transfers of facilities other than Boldman Station, United Fuel will not have recovered the cost of service of those facilities.

Atlantic Seaboard admits that prospective rate reductions are appropriate to the transfer of any of its facilities, but states that it should not be obligated also to make refunds incident to the transfer of facilities other than Boldman Station. Atlantic Seaboard requests that we delete from the order issued December 29, 1961 all provisions concerning the transfer of facilities other than Boldman Station and that, instead, any problem of related rate reductions be redelegated to the proceeding in Docket No. CP61-107.

We deem it appropriate to modify our order by removing any requirement of refunds incident to the transfer of facilities other than Boldman Station. However, we shall continue to require, as a condition to our approval of the settlement agreement, that Atlantic Seaboard prospectively reduce its rates to reflect the transfer of facilties, not limited to the transfer of Boldman Sta-

[1] Permission to transfer the Boldman Compressor Station and other facilities is being sought in the proceeding in Docket No. CP61-107.

tion.[2] Atlantic Seaboard shall, of course, remain obligated to make refunds appropriate to the transfer of the Boldman Station as provided in the approved settlement agreement.

The Commission finds:

Atlantic Seaboard's petition for reconsideration of the order issued December 29, 1961, in this proceeding should be granted as hereinafter provided.

The Commission orders:

(A) Ordering paragraph (C) of the order issued December 29, 1961, in the proceeding in Docket No. G–20272 is hereby modified to reflect the deletion of reference to refunds, and to read as follows:

(C) In the event and to the extent that transfers of its facilities are approved in the proceeding in Docket No. CP61–107, Atlantic Seaboard shall tender for filing, subject to approval by the Commission, revisions to the settlement costs of service for the period from and after the date of transfer as may be required by, or otherwise appropriate to, approval of the transfer of facilities in the proceeding in Docket No. CP61–107; if all the issues to be heard in the proceeding in Docket No. G–20272 have been determined prior to said approval of the transfer of facilities, Atlantic Seaboard shall also tender for filing, subject to approval of the Commission, revisions in rates appropriate to the revised costs of service tendered for filing as hereby required.

(B) Atlantic Seaboard's petition for reconsideration, filed herein on January 15, 1962, is hereby denied to the extent not granted in paragraph (A) above.

(C) The time within which Atlantic Seaboard shall comply with paragraph (E) of the order issued herein on December 29, 1961, is extended until 30 days from the issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

ATLANTIC SEABOARD CORPORATION, DOCKET NO. CP62–43

ORDER DENYING INTERVENTION

(Issued February 19, 1962)

A petition seeking leave to intervene in the above-entitled proceeding was filed on January 22, 1962, by Harold A. Knapp, Jr., of Germantown, Maryland (Petitioner).

This proceeding is upon an application filed by Atlantic Seaboard Corporation (Applicant) on August 22, 1961, as supplemented on October 17, 1961, pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity seeking authorization for (1) the construction and operation of approximately 40.3 miles of 30-inch gas transmission pipeline extending in a northeasterly direction from Applicant's 26-inch pipelines at Leesburg Gate, Loudoun County, Virginia, to a point of interconnection with Applicant's 20-inch and 26-inch pipelines at Linden Church, Howard County, Maryland, and (2) the installation and operation of an additional 1320 horsepower at Applicant's Lost River Compressor Station, Hardy County, West Virginia.

Petitioner a resident of Montgomery County, Maryland, states that there are four "public issues which must be considered and clarified before it may

[2] The related impact of the transfer on the rates of United Fuel will of course be considered in appropriate proceedings.

reasonably be judged that the particular facility proposed would in fact serve the public interest, and before the public can be assured that its interests have in fact been duly considered." They are:

(1) In the absence of a full hearing, Commission approval is more in the nature of failing to find any cause for objecting, on the basis of material submitted by the Applicant, rather than a positive assertion that, in the light of all the evidence, increased facilities are in fact necessary.

(2) The proposed pipeline does not follow a direct route nor does it follow the route of Applicant's existing facilities through Montgomery County, Maryland. Applicant has not stated sufficient reasons to justfy the use of a new rather than the existing right-of-way. Also, Applicant has represented to property owners along the proposed right-of-way that it would resort to condemnation proceedings unless it secured the needed right-of-way by negotiation; however, Applicant did not reveal that it could not undertake condemnation proceedings unless and until a certificate of public convenience and necessity was issued.

(3) Applicant has not justified the use of a 60-foot right-of-way for a 30-inch pipeline. Further, Applicant refuses to discuss the need for such a right-of-way with Petitioner or the Maryland-National Capital Park and Planning Commission.

(4) Applicant did not submit its proposed plans to the Maryland-National Capital Park and Planning Commission until after the request for temporary authorization had been made to the Federal Power Commission. This would have deprived the Maryland-National Capital Park and Planning Commission of an opportunity to make representations to the Federal Power Commission if temporary authorization had been granted. Furthermore, the application stated that "No application to any other Federal, State or other regulatory body will be necessary to supplement or effectuate Applicant's herein proposed project," and this is untrue.

On January 30, 1962, Applicant filed its Answer and Objection to Petition to Intervene of Harold A. Knapp, Jr. The answer states that Petitioner does not have any right to intervene conferred by statute of the United States nor does he claim any interest which may be affected directly by Commission action. Applicant further states in its answer that it has submitted sufficient information to the Commission for the Commission to make a full and complete investigation of the proposed project, that the reason for Applicant's desire to remove its pipeline from the metropolitan area is due to the rapid growth of the area, and that Applicant did in fact submit its proposed plans to the Maryland-National Capital Park and Planning Commission on October 27, 1961, together with an actual aerial survey with the proposed pipeline superimposed.

It appears that what is before us in this proceeding is the question of whether the public convenience and necessity require the construction and operation of the facilities proposed by Applicant to meet the gas requirements in the immediate future in the Washington-Baltimore area. It appears further that Petitioner desires us to consider non-jurisdictional questions raised by the application in this docket and by the purported deceitful and unco-operative conduct of Applicant.

Petitioner's contention that "in the absence of a full hearing, Commission approval is more in the nature of a failing to find any cause for objecting, on the basis of material submitted by the Applicant, rather than a positive assertion that, in light of all the evidence, increased facilities are in fact necessary" is entirely without merit. The Commission does not issue a certificate unless it finds that the applicant has complied with all of the provisions of the Natural Gas Act and that a certificate should be issued under Subsections (c) and (e)

of Section 7 of the Act. Lack of objections by the Commission to the material submitted by an applicant is not a sufficient ground for the issuance of a certificate under the Natural Gas Act, and the Commission does not, in fact, issue certificates under such circumstances. Certificates are issued only "in light of all the evidence."

Petitioner states "My own property is not involved, but my enjoyment of the area where I live and of the physical appearance of the countryside throughout Montgomery County is adversely affected by the cutting of a 60 foot wide right of way through the forested areas." In a Section 7(c) proceeding such as this, there are undoubtedly many property owners who will be indirectly affected by the action taken by this Commission. Should each be allowed to intervene upon a mere showing of property ownership, proceedings, already burdened with numerous issues, would become nigh uncontrollable. Congress has provided in the Natural Gas Act for participation as a party any interested State, State commission, municipality, or any other person whose participation in the proceeding may be in the public interest. The participation of any other party in this proceeding requires more than a tenuous likelihood of an indirect injury. Even if Petitioner's own property were directly involved, his property rights would be protected by the courts, as provided by Section 7(h) of the Natural Gas Act, where they would be given the consideration which they merit.

All other contentions made by Petitioner in his petition to intervene are likewise found to be without merit.

The Commission finds:

It is not appropriate in the proper administration of the Natural Gas Act and in the public interest to allow Petitioner to intervene in this proceeding.

The Commission orders:

The Petition to Intervene filed by Harold A. Knapp, Jr., on January 22, 1962, in Docket No. CP62-43 be and the same is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

BRADLEY EMPIRE CORPORATION, DOCKET NOS. G-18407 AND G-20201

ORDER CONDITIONALLY TERMINATING PROCEEDINGS

(Issued February 20, 1962)

On March 30, 1959, Bradley Empire Corporation (Bradley) tendered for filing Fifth Revised Sheet No. 5 to its FPC Gas Tariff, Original Volume No. 1, proposing an increase of about $63,000 per year in rates and charges for gas sold to Bradley's affiliate and sole wholesale customer, Empire Gas and Fuel Company, Limited (Empire). The increase was suspended by order issued April 29, 1959, in Docket No. G-18407 and became effective subject to refund as of June 1, 1959. The increase was based solely on increased costs of gas purchased from Bradley's supplier, New York State Natural Gas Corporation (New York Natural). New York Natural's increase had been suspended by order issued December 22, 1958, in Docket No. G-17296 and became effective subject to refund as of June 1, 1959.

On October 30, 1959, Bradley tendered for filing Sixth Revised Sheet No. 5 to its FPC Gas Tariff, Original Volume No. 1, proposing a further increase of $12,800 per year to Empire. Bradley's further increase was suspended by order issued November 20, 1959, in Docket No. G-20201 and became effective subject to

refund as of December 1, 1959. This increase was also based solely on an increase in the cost of gas purchased from New York Natural. New York Natural's further increase had been suspended by order issued July 31, 1959, in Docket No. G–19087 and became effective subject to refund as of December 1, 1959.

The staff of the Commission has completed an investigation of Bradley's books, records, and operations. It appears (see Appendix A) that the increased rates and charges proposed by Bradley do not result in revenues above its cost of service including return at 6%. Bradley accepts the staff's findings and has agreed that if its proceedings are terminated it will make appropriate refunds to Empire in the event it receives refunds from New York Natural in the proceedings in Docket Nos. G–17296 and G–19087. Therefore, the Commission, upon its own motion, deems it appropriate to terminate Bradley's proceedings, subject to the terms and conditions hereinafter ordered.

No hearings have been held or scheduled in Bradley's proceedings and no one has petitioned to intervene therein.

The Commission finds:

Good cause exists for terminating the proceedings in Docket Nos. G–18407 and G–20201, subject to the terms and conditions hereinafter ordered.

The Commission orders:

(A) The increased rates and charges tendered for filing by Bradley on March 30, 1959 and October 30, 1959, are hereby allowed as of June 1, 1959 and December 1, 1959, respectively, subject to the following terms and conditions.

(B) In the event and to the extent that New York Natural reduces its rates and charges to Bradley below those reflected in Bradley's cost of service (see Appendix A), then Bradley shall file reductions in its rates subject to the approval of the Commission.

(C) In that event and to the extent that New York Natural makes refunds to Bradley in the proceedings in Docket Nos. G–17296 and G–19087, Bradley shall make immediate proportionate refunds to Empire, including interest received.

(D) Within 15 days after the making of any refund as herein provided, Bradley shall report to the Commission, in writing and under oath, the amount of refund showing separately the amounts of principal and interest and the billing determinants or other bases used for such determinations, and shall serve a copy of such report upon Empire. Concurrently therewith, Bradley shall file a release from Empire with respect to such refund, showing receipt of principal and interest in conformity to this order.

(E) Bradley shall, over the signature of a responsible officer, file with the Commission, within 30 days from the date of issuance of this order, in writing and under oath, an original and one copy of its acceptance or rejection of the terms of this order.

(F) Upon full compliance by Bradley with all the terms and provisions of this order, the proceedings in Docket Nos. G–18407 and G–20201 shall be deemed terminated.

(G) This order is without prejudice to any findings or orders which have been or may be made hereafter by the Commission, and is without prejudice to claims or contentions which may be made by the Commission, Bradley, the Commission staff, or any affected person herein, in any proceedings now pending or hereafter instituted by or against Bradley or any other companies or any others affected by this order.

Summary cost of service

	Docket No. G-18407 Staff June 1-Nov. 30, 1959 [1]		Docket No. G-20021 Staff Calendar year 1960 [2]	
Operating expenses	$343,986		$728,103	
Depreciation, depletion and amortization	4,225		8,395	
Federal taxes on income	326		1,301	
Other taxes	1,444		3,334	
Return at 6 percent	5,482		10,130	
Total cost of service	355,463		751,263	
Gas sales revenue:				
Jurisdictional proposed	346,190		746,382	
Nonjurisdictional	1,779		4,583	
Total	347,969		750,965	
Revenue (deficiency)	(7,494)		(298)	
	Mcf	Dollars	Mcf	Dollars
Jurisdictional gas purchased from New York State Natural Gas Corp.:				
Sales proceeds	699,037	$320,629	1,456,202	$681,117
Cost	699,037	319,580	1,456,202	678,932
		[3] 1,049		[3] 2,185

[1] Closed period.
[2] No adjustments necessary to conform with 1961 operations.
[3] Sales price in excess of purchase cost exclusive of other costs.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

CENTRAL LOUISIANA ELECTRIC COMPANY, INC., DOCKET NO. CP62-129

DECLARATION OF EXEMPTION

(Issued February 20, 1962)

Central Louisiana Electric Company, Inc. (Applicant), filed an application on November 21, 1961, as supplemented on December 4, 1961, for exemption from the provisions of the Natural Gas Act pursuant to Section 1(c) thereof.

Upon the basis of the application filed, the exhibits appended thereto, and the files of the Commission, it appears that:

(1) Applicant is a Louisiana corporation having its principal place of business in Alexandria, Louisiana, and is authorized to do business in the State of Louisiana.

(2) Applicant has acquired the properties of Sabine Gas Company, Inc., and is assignee of the contract of Sabine Gas Company, Inc., to receive interstate gas from United Gas Pipe Line Company in the State of Louisiana;

(3) All natural gas received by Applicant is to be consumed ultimately within the State of Louisiana, and all of its facilities, including those acquired from Sabine Gas Company, Inc., are located within said state; and

(4) The Louisiana Public Service Commission has certified to the Federal Power Commission that it has and is exercising regulatory jurisdiction over the rates, services and facilities of Applicant.

WHEREFORE, The Commission declares, by reason of the foregoing:

Central Louisiana Electric Company, Inc., is exempt from the provisions of the Natural Gas Act, and the orders, rules, and regulations of this Commission issued thereunder.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

COLUMBIA GULF TRANSMISSION COMPANY, DOCKET NO. CP62–109

ORDER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 20, 1962)

The order of the Commission issued on January 11, 1962, in Docket No. CP62–109 authorizes Columbia Gulf Transmission Company (Columbia Gulf) to construct during the calendar year 1962 certain limited field facilities and to operate such facilities to take natural gas supplies from producers who have received authorization from the Commission "to sell natural gas to Columbia Gulf Transmission Company."

The records of the Commission show that the operation for which authorization was sought in the subject proceeding was the transportation of natural gas for the account of United Fuel Gas Company.

On January 29, 1962, Columbia Gulf filed a motion to amend the aforesaid order of the Commission issued January 11, 1962, in Docket No. CP62–109 by adding the words "or to United Fuel Gas Company" at the end of ordering paragraph (A) of said order. It appears more appropriate to amend said order as hereinafter ordered.

The Commission finds:

It is in the public interest and appropriate in carrying out the provisions of the Natural Gas Act to amend as hereinafter ordered the order of the Commission issued January 11, 1962, granting a certificate of public convenience and necessity to Columbia Gulf Transmission Company in Docket No. CP62–109.

The Commission orders:

(A) The order of the Commission issued on January 11, 1962, in Docket No. CP62–109 be and the same is hereby amended by deleting the last line of ordering paragraph (A) of said order and substituting therefore the following:

> from the Commission to sell natural gas for transportation by Columbia Gulf Transmission Company for the account of United Fuel Gas Company.

(B) In all other respects said order issued January 11, 1962, in Docket No. CP62–109 shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

DUKE POWER COMPANY, DOCKET NO. E-7018

SUPPLEMENTAL ORDER AUTHORIZING THE ISSUANCE OF FIRST AND REFUNDING MORTGAGE BONDS

(Issued February 20, 1962)

By order issued February 5, 1962, in the above-entitled matter, the Commission authorized Duke Power Company (Applicant) to issue and sell at competitive bidding $50,000,000, principal amount of First and Refunding Mortgage Bonds, Series due 1992, subject, among others, to the provisions set forth in paragraph (B) of that order, as follows:

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2 (k) (3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations;

(ii) The Commission by a further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

Applicant, on February 20, 1962, filed an amendment, pursuant to the requirements of the afore-mentioned Commission order, setting forth, among other things, that it proposes to accept as providing the lowest annual cost of money to it the bid of Stone & Webster Securities Corporation to purchase the proposed issuance of $50,000,000, principal amount of Bonds, for the price of 99.269% of principal amount, with an interest rate of 4½%.

The Commission finds:

(1) Applicant has satisfactorily complied with the requirements of paragraph (B) of the Commission's order issued February 5, 1962 in the above docket, and under the bid it proposes to accept for the Bonds, the price to be received by Applicant therefor and the interest rate thereof are reasonable.

(2) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The price to be received by Applicant for the proposed Bonds and the interest rate thereof under the bid referred to above are approved as reasonable.

(B) The proposed issuance and sale of Bonds referred to above, upon the terms and conditions and for the purposes specified in the application, as supplemented by the amendment referred to above, are authorized, subject only to the provisions of paragraphs (A), (C), (D) and (E) of the Commission's order issued February 5, 1962 in the above docket.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NO. CP62-114

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 20, 1962)

On November 3, 1961, El Paso Natural Gas Company (Applicant) filed in Docket No. CP62-114 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the sale and delivery of an additional 100,000 Mcf of natural gas per day to Pacific Gas and Electric Company (PG&E) at an existing delivery point near Topock, Arizona, on a best efforts basis for the limited term commencing December 1, 1961, and extending through April 30, 1962, all as more fully set forth in the application.

The subject 100,000 Mcf of natural gas are in addition to the presently certificated quantities of gas delivered by Applicant to PG&E and are to be provided from Applicant's existing sources of supply by use of its certificated pipeline facilities only after meeting its other customer requirements throughout its pipeline system.

No additional facilities are proposed by Applicant for the subject service which will be rendered by Applicant in accordance with a service agreement between Applicant and PG&E dated October 12, 1961, and at rates contained in Applicant's FPC Gas Rate Schedule G-X-1 on file with the Commission as part of its FPC Gas Tariff, Original Volume No. 1.

The proposed service will aid Applicant in disposing of a short-term oversupply of gas and will aid PG&E in meeting its system requirements.

Applicant received authorization to render similar service to PG&E in Docket No. CP60-80 and has submitted the instant application for an extension of that service.

Temporary authorization to render the proposed service was granted to Applicant on December 4, 1961.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 8, 1962, respecting the matters involved in and the issues presented by the application herein. No protest or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, El Paso Natural Gas Company, a Delaware corporation having its principal place of business in El Paso, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 29, 1942, in Docket Nos. G-242 and G-257 (3 FPC 851).

(2) The proposed sale of natural gas as hereinbefore described, as more fully described in the application in this proceeding, will be made in interstate commerce, subject to the jurisdiction of the Commission, and is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The proposed sale of natural gas as hereinbefore described, and as more fully described in the application in this proceeding, is required by the public

convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of said Regulations.

(6) The authorization granted hereinafter should be limited to sales during the period from December 4, 1961 through April 30, 1962, and deliveries should be limited to a maximum of 100,000 Mcf per day.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing El Paso Natural Gas Company to sell up to 100,000 Mcf of natural gas per day to Pacific Gas and Electric Company on an interruptible best efforts basis for the period from December 4, 1961 through April 30, 1962, as hereinbefore described and as more fully described in the application in this proceeding.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of said Regulations.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NO. CP62-122

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND ACCEPTING RATE FILING

(Issued February 20, 1962)

On November 14, 1961, El Paso Natural Gas Company (Applicant) filed in Docket No. CP62-122 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the sale and delivery of additional natural gas to Northwest Natural Gas Company (Northwest Natural), an existing customer, for resale and distribution in the communities of Scappoose and St. Helens, Columbia County, Oregon, and environs, all as more fully set forth in the application.

Applicant proposes to make delivery to Northwest Natural at the existing measuring and regulating station located at the terminus of Applicant's 18-inch O.D. Portland-Vancouver sales lateral near Portland, from which point Northwest Natural will construct the necessary connecting line and the distribution systems at Scappoose and St. Helens.

Northwest Natural estimates the annual and peak day requirements of the two communities as follows:

	1st year	Mcf at 14.73 psia	
		2d year	3d year
Peak day	3,493	5,524	8,455
Annual	909,600	1,492,000	2,329,000

The sale by Applicant will be on a firm and an interruptible basis. The gas will be used for residential, commercial and industrial purposes by the ultimate consumers.

Service under this application is proposed to be rendered in accordance with revised exhibits to service agreements contained in Applicant's FPC Gas Tariff, Original Volume No. 3, which revised exhibits were filed concurrently with the instant application.

No new facilities or construction by El Paso are necessary for this additional service.

The proposed service should not seriously affect Applicant's gas supply nor impair its ability to meet its other firm obligations.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 6 and 7, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, El Paso Natural Gas Company, a Delaware corporation having its principal place of business in El Paso, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 29, 1942, in Docket Nos. G–242 and G–257 (3 FPC 851).

(2) The sale and delivery of natural gas by Applicant for resale, as hereinbefore described and as more fully described in the application in this proceeding, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The proposed sale and delivery of natural gas by Applicant to Northwest Natural Gas Company for resale are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate hereinafter issued and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3) and (e) of Section 157.20 of such Regulations.

(6) Applicant's tendered related revised Exhibit A dated November 2, 1961, to the service agreement between Applicant and Northwest Natural dated May 18, 1961, and the related revised Exhibits A and B dated November 2, 1961, to the service agreement between said parties dated May 15, 1961, should be accepted for filing to become effective upon the date of issuance of this order.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing El Paso Natural Gas Company to sell and deliver natural gas to Northwest Natural Gas Company for resale as hereinbefore described and as more fully described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), and (e) of Section 157.20 of such Regulations.

(C) The sale and delivery of natural gas authorized by this order shall commence within 12 months of the date on which this order issues.

(D) Applicant's tendered related revised Exhibit A dated November 2, 1961, to the service agreement between Applicant and Northwest Natural dated May 18, 1961, and the related revised Exhibits A and B dated November 2, 1961, to the service agreement between said parties dated May 15, 1961, are hereby accepted for filing to become effective upon the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

LAKE SHORE PIPE LINE COMPANY, DOCKET NO. CP62-137

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 20, 1962)

On December 1, 1961, Lake Shore Pipe Line Company (Applicant), filed in Docket No. CP62-137 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the twelve-month period commencing on the date on which the order in this docket issues, at a total cost not to exceed $250,000, with no single project to exceed a cost of $50,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

The proposed facilities will be financed from cash on hand or short term bank loans.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 8, 1962, respecting the matters involved in and the issues presented by the application in this proceeding. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the

Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Lake Shore Pipe Line Company, an Ohio corporation having its principal place of business in Cleveland, Ohio, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order issued February 13, 1951, in Docket No. G–1236 (10 FPC 22).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing pipeline system and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of facilities to take natural gas purchased from producers thereof during the twelve-month period as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit within sixty days from the expiration of the twelve-month period for which the order in this docket is issued, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization granted hereunder, (d) the location of said project or projects, (e) the cost of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(6) The authorization granted herein should be limited to construction during the twelve-month period commencing on the date on which this order issues, and the total cost for facilities to be constructed hereunder should be limited to $250,000, with no single project to exceed a cost of $50,000.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Lake Shore Pipe Line Company to construct during the twelve-month period commencing on the date on which this order issues the proposed facilities hereinbefore described (more fully described in the application filed in this proceeding) and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Lake Shore Pipe Line Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(C) Applicant shall submit within sixty days from the expiration of the twelve-month period for which this order is issued a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(D) Total expenditures for the construction of the facilities authorized by paragraph (A) above are hereby limited to $250,000, with no single project to exceed a cost of $50,000.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

NORTHERN NATURAL GAS COMPANY, ET AL., DOCKET NOS. G–17485, ET AL.

ORDER AMENDING ORDER ACCOMPANYING OPINION NO. 324

(Issued February 20, 1962)

On August 28, 1961, as supplemented November 15, 1961, the Town of Woodbine, Iowa, filed an application for amendment of the order accompanying Opinion No. 324, issued July 31, 1959, in the above-entitled proceeding, 22 FPC 164, requesting that the Town be substituted for Iowa Power and Light Company (Iowa Power) as the distributor of gas in Woodbine. The order accompanying Opinion No. 324 had authorized Northern Natural Gas Company (Northern), *inter alia*, to sell and deliver gas to Iowa Power for distribution in the Town of Woodbine provided Iowa Power made a contribution to Northern toward construction of the measuring station necessary to deliver natural gas to Woodbine. Woodbine's application requests that Northern be authorized to sell and deliver gas to Woodbine, instead of Iowa Power, because Woodbine now proposes to construct a municipally-owned distribution system.[1]

Northern filed on July 31, 1961, a "Petition for Further Amendment" of the order accompanying Opinion No. 324 requesting that the authorization it had originally received to construct the facilities necessary to serve Woodbine be deleted. On November 1, 1961, the Commission issued an order in Docket Nos. G–17485, *et al.*, 26 FPC 672, granting Northern's petition, except for deferring action on Northern's request to have its authorization to construct the facilities required to serve Woodbine deleted from the order accompanying Opinion No. 324 until such time as the Commission had made a final determination regarding Woodbine's application for amendment of the order accompanying Opinion No. 324.

[1] Attached to Woodbine's application is a copy of Ordinance No. 63, passed by the Town Council of Woodbine on November 7, 1960, canceling and terminating the gas-distribution franchise which Iowa Power had previously received on June 4, 1954.

Northern indicated in an answer to Woodbine's application, filed December 20, 1961, that it would not object to rendering town-border service to Woodbine provided the Town would sign appropriate service agreements and would make a contribution toward the cost of constructing the measuring station in the amount of $14,200, which was the sum Iowa Power would have had to pay if it had become the gas distributor in Woodbine. Woodbine's application states that it is willing to make the required contribution toward the cost of construction. Since Northern is now willing to provide gas for Woodbine's proposed municipal system, that portion of Northern's petition, filed July 31, 1961, requesting deletion from the order accompanying Opinion No. 324 of authorization to construct the facilities required to serve Woodbine will necessarily have to be denied.

Woodbine has submitted detailed engineering studies in support of its estimated sales volumes, cost of construction and economic feasibility. It estimates that its first, second, and third-year peak daily requirements will be 393 Mcf, 466 Mcf and 538 Mcf, respectively, and that the first, second, and third-year annual requirements will be 57,490 Mcf, 65,110 Mcf and 72,730 Mcf, respectively. The cost of construction of the distribution system is estimated at $200,000, including an allowance for the contribution to Northern in aid of construction.

Woodbine proposes to finance the project by issuing $200,000 in municipal gas system revenue bonds which will have a 20-year maturity with an interest rate of 4.5 percent for the first 10 years and 4.75 percent for the remaining 10-year period. The application states that the Carleton D. Beh Company, Des Moines, Iowa, has entered into an agreement with Woodbine for financing the distribution system.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act (1) that the Town of Woodbine's application for amendment, filed August 28, 1961, of the order accompanying Opinion No. 324 be granted and (2) that Northern's "Petition for Further Amendment", filed July 31, 1961, be denied insofar as it requested deletion from the order accompanying Opinion No. 324 of authorization to construct the facilities required to serve Woodbine, Iowa.

The Commission orders:

(A) Paragraph (A) of the Commission's order accompanying Opinion No. 324, issued July 31, 1959, 22 FPC 164, 179, as amended August 26, 1960, 24 FPC 341, and November 1, 1961, 26 FPC 672, is hereby further amended to authorize Northern to sell and deliver natural gas to the Town of Woodbine for its proposed municipal distribution system, instead of to Iowa Power and Light Company, provided the Town of Woodbine makes the contribution in aid of construction hereinbefore discussed.

(B) That portion of Northern's "Petition for Further Amendment", filed July 31, 1961, which requested deletion from the order accompanying Opinion No. 324 of Northern's authorization to construct the facilities required to serve Woodbine, Iowa, is hereby denied.

(C) All other provisions of the order accompanying Opinion No. 324, 22 FPC 179, as amended August 26, 1960, 24 FPC 341, and November 1, 1961, 26 FPC 672, shall remain unchanged.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. CP62-14; THE MANUFACTURERS LIGHT & HEAT COMPANY, DOCKET NO. CP61-155

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 20, 1962)

These matters are before us upon a motion made upon the record on December 18, 1961, by Tennessee Gas Transmission Company (Tennessee) and The Manufacurers Light and Heat Company (Manufacturers) for disposition of these matters as non-contested proceedings and for omission of the intermediate decision procedure. All parties participating in the hearing concurred in said motion.

The proceedings are upon applications filed pursuant to Section 7 of the Natural Gas Act for certificates of public convenience filed by Manufacturers and Tennessee on November 25, 1960, and July 19, 1961, respectively.

By its application filed July 19, 1961, Tennessee, a Delaware corporation having its principal place of business in Houston, Texas, seeks a certificate of public convenience and necessity authorizing it to transfer the deliveries of 35,000 Mcf[1] of gas per day, which is part of the contract-demand volume Tennessee is presently delivering to United Fuel Gas Company (United) in Tennessee's Eastern Rate Zone, to Manufacturers for the account of United in Tennessee's Northern Rate Zone. The transfer of deliveries is proposed to be for the six months period commencing on November 1, 1961, and ending on April 30, 1962, and for each six months period thereafter that commences on November 1st and ends on April 30th for a term of years coextensive with the term of the gas sales contract between Tennessee and United dated May 4, 1959.

By its application filed November 25, 1960, as supplemented on February 20, April 10, and July 21, 1961, Manufacturers seeks a certificate of public convenience and necessity authorizing it to construct and operate 4,000 additional horsepower compressor units at its existing Adaline Compressor Station in Marshall County, West Virginia, and approximately 10.47 miles of 24-inch pipeline in several sections replacing corresponding sections of 16-inch pipeline in Manufacturer's Line 65 in the western part of Allegheny, and adjoining portions of Washington and Beaver Counties, Pennsylvania. The cost of facilities is estimated to be $2,387,000, which will be financed from funds obtained from The Columbia Gas System, Inc.

Tennessee shows that it is presently authorized to sell and deliver to United a contract demand of 544,680 Mcf of natural gas per day, under the terms of a gas sales contract between Tennessee and United dated May 4, 1959. Said contract provides for the delivery of 76,500 Mcf of natural gas per day in Tennessee's Central Rate Zone and 468,180 Mcf of natural gas per day in Tennessee's Eastern Rate Zone.

Tennessee shows also that it is authorized to sell and deliver to Manufacturers a contract demand of 30,600 Mcf of natural gas per day, in accordance with a gas sales contract between Tennessee and Manufacturers dated January 28, 1959, which provides for said delivery in Tennessee's Northern Rate Zone. In addition, Tennessee transports for the account of Manufacturers up to 113,371

[1] All volumes set forth herein are at a pressure base of 14.73 psia unless otherwise indicated.

Mcf of natural gas per day that is purchased by Manufacturers from producers in the State of Texas. Of this amount, 36,871 Mcf per day is delivered by Tennessee in its Eastern Rate Zone and the balance is delivered in its Northern Rate Zone.

The evidence shows that United is presently delivering a contract demand of 185,000 Mcf of natural gas per day to Manufacturers. United has been requested by Manufacturers to provide it with a contract demand of 220,000 Mcf per day commencing on November 1, 1961. United has adequate capacity to deliver this volume to Manufacturers at existing delivery points. Manufacturers' facilities are adequate [2] to transport a volume of 220,000 Mcf per day during the summer months, but are inadequate to transport such volume during the winter months of November through April. The evidence further shows that in order to provide adequate pipeline capacity to transport 220,000 Mcf of natural gas per day during the peak winter months, Manufacturers would be required to construct twenty miles of 20-inch pipeline loop of its Line No. 1740 at a point north of Glenville, Pennsylvania at a cost of approximately $1,900,000. In order to avoid this expenditure, Manufacturers and United have requested Tennessee to transfer the deliveries of 35,000 Mcf of natural gas per day which is presently being delivered to United in Tennessee's Eastern Rate Zone to Manufacturers, for the account of United, in Tennessee's Northern Rate Zone for the six-month period commencing on November 1, 1961, and ending on April 30, 1962, and for each six-month period thereafter that commences on November 1st and ends on April 30th, for a term of years coextensive with the term of the gas sales contract between Tennessee and United. Tennessee's application in Docket No. CP62–14 seeks authority to make this transfer of deliveries.

Tennessee shows that it is able to render the proposed service with its existing facilities; that its requirements customers in its Southern and Central Rate Zones purchase gas at high load factors during the winter months of November through April. Thus, Tennessee's pipeline system has unused winter-day capacity between Station No. 87 near Portland, Tennessee, and Tennessee's storage fields in northern Pennsylvania and New York.

Tennessee and United have entered into a letter-agreement dated July 13, 1961, providing for this proposed service.

Tennessee also presented in evidence the superseding service agreement dated October 10, 1961, between it and United providing for the transfer of the deliveries of 34,314 Mcf (@15.025 psia) of natural gas per day of contract demand from Tennessee's Eastern Rate Zone for the period from November 1, 1961, through April 30, 1962, and during each six months period thereafter, November through April until November 1, 1979, which agreement became effective by order of the Commission of December 8, 1961.

Manufacturers shows that the proposed pipeline facilities are necessary in order to increase the capacity of its main trunk transmission system to make it possible to serve 1961–1962 peak day additional requirements of its customers, while the 4,000 additional horsepower compression facilities are necessary in order to inject and withdraw additional gas into and from storage. Manufacturers' most recent estimates indicate that its 1961–1962 winter additional gas requirements total 79,700 Mcf per day or 47,500 Mcf per day more than initially estimated in its original application.

It was originally proposed that the additional volumes of natural gas (32,200 Mcf per day) were to come from Manufacturers' Victory Storage Field. Manu-

[2] This assumes that Manufacturers will be authorized to construct the facilities proposed in Docket No. CP61–155.

facturers now proposes to meet its additional 1961–1962 winter requirements of 79,700 Mcf (47,500 Mcf plus 32,200 Mcf) as follows:

Additional volume from United (Tennessee's Northern Zone)	35,000 Mcf
Additional volume from Victory Storage Field	45,000 Mcf
	80,000 Mcf

Manufacturers' evidence shows that the peak-day availability from the Victory Storage Field will be increased from 160,000 Mcf to 205,000 Mcf and of this volume 183,000 Mcf is to be compressed at Adaline Compressor Station, so that substantially all of the proposed 4,000 additional horsepower will be required.

Manufacturers shows that it will increase its contract demand with United from 185,000 to 220,000 Mcf per day to provide it with the additional 35,000 Mcf per day. Manufacturers' evidence corroborates that of Tennessee to the effect that the existing facilities of Manufacturers are adequate to transport the higher volume of 220,000 Mcf per day during the summer period, but to provide such adequacy during peak winter periods would require substantial transmission construction.

Tennessee was by order of the Commission on December 14, 1961, permitted to intervene in Docket No. CP61–155. Likewise, by the same order Manufacturers and United were permitted to intervene in Docket No. CP62–14. The Commission also permitted the intervention of thirty-eight additional interveners, including customers of Tennessee, the Public Service Commission of West Virginia, Pennsylvania Public Utility Commission, Public Utilities Commission of the State of Connecticut, Department of Public Utilities of the Commonwealth of Massachusetts, Division of Public Utilities of the State of Rhode Island, the City of Pittsburgh, Pennsylvania, Washington Gas Light Company, Commonwealth Natural Gas Corporation, The Dayton Power and Light Company, Cincinnati Gas & Electric Company and The Union Light, Heat and Power Company. However, only the following interveners, besides the parties, appeared by counsel at the hearing, which was held on December 18, 1961, and January 2, 1962, pursuant to due notice: Pennsylvania Public Utility Commission, City of Pittsburgh, and companies receiving their supplies of gas from Columbia Gas System Companies, i.e., The Dayton Power and Light Company, The Cincinnati Gas & Electric Company, The Union Light, Heat and Power Company, Washington Gas Light Company, and Commonwealth Natural Gas Corporation.

The above-named company interveners, who receive either directly or indirectly a major portion of their gas supplies from United, objected to the proposed transfer of deliveries of 35,000 Mcf of gas per day in Tennessee's Northern Rate Zone instead of in its Eastern Rate Zone because it would increase the cost of the gas to United by approximately $239,000 per year. It was stipulated and agreed at the hearing by all the parties appearing that the additional cost of purchasing this gas at the Northern Zone rate should be borne by Manufacturers, because such additional cost will be incurred for the benefit of Manufacturers and the delivery will be made a substantial distance outside United's operating territory. It was agreed that a condition be attached to the certificates issued herein requiring United to file as a part of its FPC Gas Tariff, Original Volume No. 2 an appropriate agreement, satisfactory to the Commission, providing that any net additional cost incurred by United in purchasing said 35,000 Mcf of natural gas per day for the period of six months per year, November through April, in the Northern Rate Zone

over and above the cost of purchasing such volume of gas in the Eastern Zone shall be reimbursed by Manufacturers to United.

At the close of the hearing, it was agreed that staff counsel would prepare and distribute to all of the participating parties on or before January 2, 1962, a draft of a proposed order which would be transmitted to the Commission together with the record and the motion for omission of the intermediate decision. It was further agreed that the hearing would reconvene on January 15 for the submission of said draft and that any party who might have any objection might be present to object. Said proposed draft, with minor changes made for purposes of clarification only, was submitted on said date.

It appears to the Commission that there is a serious question as to whether the granting of these applications will not place Manufacturers in the position of making payments to United for a service which United does not render. If this is the case, then it is not appropriate for United to make a charge for a service it does not render.

An additional question arises as to whether the proposed arrangement appropriately falls within the scope of a Volume No. 2 tariff filing, inasmuch as Section 154.52 of the Commission's Regulations under the Natural Gas Act limits Volume No. 2 tariff filings to cover special operating arrangements such as for exchange or transportation of natural gas, or for the sale of gas at charges computed on a cost-formula basis.

Under the circumstances, we are of the view that the certificate authorization should be issued to Tennessee for the current winter season as well as the 1962–1963 winter season, but that continuation of the arrangement on a long term basis should be permitted only on the basis of a record developed in a formal hearing. Accordingly, the Commission on its own motion will remand these proceedings to the Presiding Examiner to be set for further hearing with notice to be given by the Secretary.

Temporary authority was granted on August 18, 1961, to Tennessee, as requested in its application in Docket No. CP62–14, to make the proposed transfer of deliveries as of November 1, 1961. Temporary authority was also granted by the Commission on said date to Manufacturers to construct and operate the facilities proposed in Docket No. CP61–155.

The Commission finds:

(1) Tennessee Gas Transmission Company, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of July 12, 1947, in Docket No. G–910, (6 FPC 777).

(2) The proposed transfer by Tennessee of deliveries of 35,000 Mcf of natural gas per day, that is presently being delivered by Tennessee to United in Tennessee's Eastern Rate Zone, to Manufacturers, for the account of United, in Tennessee's Northern Rate Zone, as described in the application in Docket No. CP62–14, is required by the public convenience and necessity for two six months periods, the first commencing on the date of first delivery in the Northern Rate Zone on November 1, 1961, and ending April 30, 1962, and the second period commencing on November 1, 1962, and ending April 30, 1963, and a certificate therefor should be issued.

(3) The Manufacturers Light and Heat Company, a Pennsylvania corporation and a subsidiary of The Columbia Gas System, Inc., having its principal place of business in Pittsburgh, Pennsylvania, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of December 29, 1944, in Docket Nos. G–593, *et al.* (4 FPC 821).

(4) The natural gas facilities proposed to be constructed and operated by The Manufacturers Light and Heat Company, as described in the application in Docket No. CP61–155, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as an integral part of Manufacturers' existing pipeline system and the operation thereof by Manufacturers is subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) The proposed construction and operation of facilities by The Manufacturers Light and Heat Company, as described in the application in Docket No. CP61–155, are required by the public convenience and necessity and a certificate therefor should be issued.

(6) The applicants herein are able and willing to do the acts and perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(7) Public convenience and necessity require that the certificates issued hereinafter and the rights granted thereunder be conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said regulations, and the terms and conditions set forth in paragraph (c) (4) of said section should also attach to the certificate issued to Manufacturers.

(8) Public convenience and necessity require that the certificate hereinafter issued to Tennessee Gas Transmission Company be conditioned to become effective upon the filing by United Fuel Gas Company as a part of its FPC Gas Tariff, Original Volume No. 2 an appropriate agreement, satisfactory to the Commission, between The Manufacturers Light and Heat Company and United Fuel Gas Company, providing that Manufacturers shall reimburse United for any net additional cost of purchasing said 35,000 Mcf of natural gas per day at Tennessee's Northern Zone rate over the cost of purchasing such volume at Tennessee's Eastern Zone rate, for the six months period commencing on the date of first delivery in said Northern Rate Zone on November 1, 1961, and ending April 30, 1962, and also for the period commencing November 1, 1962, and ending April 30, 1963.

(9) Tennessee and Manufacturers having requested the omission of the intermediate decision procedure, and all the requirements of Section 1.30(c)(1) [18 CFR 1.30(c)(1)] of the Commission's Rules of Practice and Procedure having been satisfied, sufficient cause exists for the Commission forthwith to render its final decision in the instant proceeding.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued to Tennessee Gas Transmission Company authorizing it to transfer the deliveries of 35,000 Mcf (at 14.73 psia) of natural gas per day, which is part of the volume of gas which Tennessee is presently delivering to United Fuel Gas Company in Tennessee's Eastern Rate Zone, to The Manufacturers Light and Heat Company, for the account of United, in Tennessee's Northern Rate Zone, as described in the application in Docket No. CP62–14, for two six months periods, the first commencing on the date of first delivery in said Northern Rate Zone on November 1, 1961, and ending April 30, 1962, and the second period commencing on November 1, 1962, and ending on April 30, 1963, upon the terms and conditions of this order.

(B) A certificate of public convenience and necessity be and the same is hereby issued to The Manufacturers Light and Heat Company, authorizing it to construct and operate the proposed facilities, as described in the application, as supplemented, herein, upon the terms and conditions of this order.

(C) The certificates issued by paragraphs (A) and (B) above and the rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations; and the terms and conditions set forth in paragraphs (c) (4) of said section shall attach to the certificate issued by paragraph (B), and to the exercise of the rights granted thereunder.

(D) The certificates herein issued in paragraphs (A) and (B) shall become effective upon the filing by United Fuel Gas Company as a part of its FPC Gas Tariff, Original Volume No. 2 an appropriate agreement, satisfactory to the Commission, between The Manufacturers Light and Heat Company and United Fuel Gas Company, providing that Manufacturers shall reimburse United for any net additional cost of purchasing said 35,000 Mcf of natural gas per day at Tennessee's Northern Zone rate over the cost of purchasing such volume at Tennessee's Eastern Zone rate, and providing that said reimbursement shall cover two six months periods, the first commencing on the date of the first delivery in the Northern Zone on November 1, 1961, and ending on April 30, 1962, and the second commencing on November 1, 1962, and ending on April 30, 1963.

(E) These proceedings are hereby remanded to the Presiding Examiner for further hearing to determine whether the transfer of deliveries of natural gas herein authorized for two winter seasons shall be continued for the term of years coextensive with the term of the gas sales contract between Tennessee and United. The Presiding Examiner shall fix the date for further hearing in these proceedings.

Before Commissoners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr. and Charles R. Ross.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. CP62-107

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 20, 1962)

On October 27, 1961, as supplemented on November 27, 1961, Transcontinental Gas Pipe Line Corporation (Transco) filed in Docket No. CP62-107 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of natural gas facilities and the sale of natural gas, as hereinafter described, all as more fully described in the application, as supplemented.

The proposed facilities consist of a sales meter station and appurtenant facilities in Hudson County, New Jersey, near Transco's Central Manhattan meter station on the west bank of the Hudson River. The proposed meter station will be used as an additional delivery point to provide gas service to Public Service Electric and Gas Company (Public Service), and existing customer, for resale.

Public Service has requested the proposed new delivery point in order that it might serve a new industrial customer, Lever Brothers Company (Lever Brothers), on a firm basis, which service Public Service would be unable to render from its existing facilities. Public Service will construct and operate the required facilities between the proposed meter station and Lever Brothers' plant, and such service will be rendered from authorized allocations of gas from Transco.

The proposed facilities are estimated to cost approximately $22,000, and will be financed initially by Transco from its general funds. Public Service has agreed to reimburse Transco in full for the cost of the facilities.

Temporary authorization was granted to Transco on December 28, 1961, to construct and operate the proposed facilities.

The acceptance for filing by Transco of a revision of Section 5(a) of the General Terms and Conditions of its FPC Gas Tariff, Original Volume No. 1, renders unnecessary any consideration of the request in the instant application for waiver of the former provision in said Section 5(a) requiring the installation of measuring facilities at Transco's own expense.

Pursuant to due notice, a public hearing was held February 6, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, in this proceeding. No protest or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practic and Procedure.

The Commission finds:

(1) Applicant, Transcontinental Gas Pipe Line Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of November 18, 1948, in Docket No. G–1143 (7 FPC 145).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Transco's existing system, and the construction and operation thereof by Transco are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities by Transco are required by the public convenience and necessity, and a certificate thereof should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Transco's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations, and that the construction of the facilities authorized by this order should be completed and said facilities placed in actual operation within three months from the date on which this order issues.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Transcontinental Gas Pipe Line Corporation, to construct and operate the proposed facilities as hereinbefore described, and as more fully described in the application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The construction of the facilities authorized by this order shall be completed and said facilities shall be placed in actual operation within three months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TEXAS EASTERN TRANSMISSION CORPORATION, DOCKET NOS. CP60–122 AND CP61–203; ALGONQUIN GAS TRANSMISSION CORPORATION, DOCKET NOS. CP60–124 AND CP61–220; UNITED GAS PIPE LINE COMPANY, DOCKET NO. CP61–151; SOUTHERN NATURAL GAS COMPANY, DOCKET NO. CP61–206; TEXAS GAS TRANSMISSION CORPORATION, DOCKET NO. CP61–247; ARKANSAS MISSOURI POWER COMPANY, DOCKET NO. CP62–20.

ORDER PERMITTING AND DENYING INTERVENTIONS

(Issued February 21, 1962)

Petitions for leave to intervene in the above-entitled consolidated proceedings were filed by the named petitioners on the dates indicated and in the dockets specified:

* * * * * * *

*Petitioner**	*Docket No.*	*Date filed*
Joint Adair County Petitioners: Billie Gist, Gradyville, Kentucky. Chesley G. Rogers, 1912 Crimson Ave., Valley Station, Kentucky. L. R. Seaborn, Casey Creek, Kentucky. Nell Richard, Gradyville, Kentucky. Morton Smith, Milltown Route, Columbia, Kentucky.	All	Feb. 1, 1962

The Joint Adair County Petitioners aver that " * * * they are all owners of lands lying within or in close proximity to the existing pipelines of Texas Eastern Transmission Corporation in Adair County, Kentucky, and the interests of petitioners in such land will or may be seriously affected by any action taken or orders entered in these proceedings by the Commission" (paragraph 2). As relief, they state their, "desire that any permission granted to Texas Eastern Transmission Corporation for the placing of additional pipelines, and which involve the running of such pipelines across or within the limits of land owned by these petitioners or any of them, shall take into account and contain adequate provision for full and reasonable compensation to these petitioners for such use or taking of their property" (paragraph 3).

On February 12, 1962, Texas Eastern filed an answer, stating *inter alia*, that the Joint Adair County Petition does not comply with Section 1.8 of the Commission's Rules of Practice and Procedure in that no facts are set forth to show

* Additional petitioners omitted in printing.

that intervention by the petitioners is necessary or appropriate to the administration of the Natural Gas Act or that petitioners' participation may be in the public interest.

Section 7(h) of the Natural Gas Act, 15 USC 717 (f), (h) does confer the right of eminent domain on a holder of a certificate of public convenience and necessity should the holder be unable to acquire by contract or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way. However, this section specifically gives the jurisdiction over these eminent domain proceedings to the State courts and the United States District courts in which the property is located.

In a complex Section 7 proceeding such as this, there are undoubtedly many property owners who will be indirectly affected by the action taken by this Commission. Should each be allowed to intervene on a mere showing of property ownership, proceedings, already burdened with numerous parties and issues, would become nigh uncontrollable. Congress has provided that their property rights be protected by the courts where they will be given the proper consideration which they merit.

Since the Joint Adair County Petitioners fail to show that they have an interest of such nature that intervention is necessary or appropriate to the administration of the Natural Gas Act, the petition will therefore be denied.

The Pennsylvania Public Utility Commission filed a Notice of Intervention in Docket Nos. CP61–203, CP61–151, CP61–206, and CP61–247 on January 17, 1962.

The Commission finds:

(1) It is desirable to allow the above-named petitioners, except the Joint Adair County Petitioners, to intervene in these proceedings in order that said petitioners may establish the facts and law from which the nature and validity of their alleged rights and interests may be determined and show what further action may be appropriate under the circumstances in the administration of the Natural Gas Act. Although the petition of Southern Natural Gas Company was not filed within the time required by Section 1.8(d) of the Commission's Rules of Practice and Procedure, good cause has been shown why the participation of said petitioner may be in the public interest.

(2) The above-named Adair County petitioners have failed to show that their participation in these proceedings may be in the public interest.

The Commission orders:

(A) The above-named petitioners, except the Joint Adair County Petitioners, are hereby permitted to intervene in these proceedings, subject to the rules and regulations of the Commission: *Provided, however*, that the participation of each intervener shall be limited to matters affecting asserted rights and interests as specifically set forth in its petition for leave to intervene: And, *Provided, further*, that the admission of these interveners shall not be construed as recognition by the Commission that they or any of them might be aggrieved because of any order or orders of the Commission entered in these proceedings.

(B) The petition of the above-named Adair County Petitioners is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

BLANCO OIL COMPANY (OPERATOR), ET AL.

ORDER DENYING APPLICATION FOR REHEARING

(Issued February 23, 1962)

On December 1, 1961, Blanco Oil Company (Operator), *et al.* (Blanco) tendered for filing a proposed rate increase from 18.0¢ to 20.0324¢ per Mcf at 14.65 psia for natural gas sold under its FPC Gas Rate Schedule No. 9 to Natural Gas Pipeline Company of America from leases in the Northeast Thompsonville Field, Webb and Jim Hogg Counties, Texas (District No. 4). The subject sale is being made under temporary authority granted to Blanco by the Commission's letter order of November 25, 1960 in Docket No. CI61-618, conditioned at an initial rate of 18.0¢ per Mcf, including tax reimbursement and dehydration, in lieu of the 20.0324¢ per Mcf initial rate provided by contract. By letter order issued December 28, 1961, the Commission rejected Blanco's December 1, 1961 submittal as not in accord with the temporary authorization granted by the order of November 25, 1960.

On January 26, 1962, Blanco filed an application for rehearing of the Commission's letter order of December 28, 1961. In support thereof, Blanco states, *inter alia*, that (1) in accepting the conditioned temporary authorization, Blanco expressly reserved the right to file for rate increases in accordance with the terms of its contract;[1] (2) imposition of an initial rate below the initial contract price did not alter Blanco's right to file for the initial contract price; (3) if the Commission intended to impose as a condition to the issuance of the temporary authorization that the 18¢ per Mcf rate be maintained during the period of the temporary authorization, it was compelled fully and precisely to inform Blanco of such fact prior to Blanco's acceptance thereof; (4) Blanco's right to file for an increased rate is not altered by the fact that temporary, not permanent, authorization is involved here; and (5) Blanco will suffer irreparable loss, if not permitted to file the proposed increased rate, in the event the contract price is ultimately determined to be just and reasonable.[2]

The holder of a temporary price-conditioned certificate is not authorized to change the *status quo*, pending disposition of an application for a permanent certificate, by filing a change in rate schedule. Furthermore, in accepting temporary authorization, Blanco specifically agreed that the rate during the period of temporary authorization shall be 18.0¢ per Mcf, as indicated by the

[1] The pertinent language in Blanco's January 16, 1961 letter accepting temporary authorization is as follows: "Blanco Oil Company accepts the price condition imposed by paragraph (1) of the letter order of the Commission dated November 25, 1960, and specifies hereby that the initial price to be paid by Natural Gas Pipeline Company of America for the natural gas sold under Blanco Oil Company FPC Gas Rate Schedule No. 9 *during the period the temporary authorization granted by said letter order of November 25, 1960, is in effect shall be 18 cents per Mcf* including tax reimbursement and dehydration charge; provided, however, that in the event the Commission shall announce or fix an area price applicable to the area where this sale is made which is higher than 18 cents per Mcf, including tax reimbursement and dehydration charge, then Blanco Oil Company shall be entitled to collect such higher price, but not to exceed the applicable contract price, without any obligation to refund; and provided further, that the right of Blanco Oil Company to file for price increases in accordance with the terms of its gas sales contract dated September 1, 1960, is expressly recognized by the acceptance of this filing." [Emphasis added]

[2] In support of its last contention, Blanco cites *Sohio Petroleum Company* v. *F.P.C.*, 10th Cir., December 19, 1961, and *The Pure Oil Company* v. *F.P.C.*, 292 F. 2d 350.

underlined portion of its acceptance letter set forth in footnote 1, *supra*.[3] Under the circumstances, we think there is no merit to Blanco's argument that the Commission should have been more explicit as to the limitation imposed with respect to subsequent rate filings during the period of the temporary authorization. In like manner, Blanco's attempt to now attack the Commission's power to so condition the issuance of a temporary certificate represents an unwarranted collateral attack on the November 25, 1960 letter order of the Commission granting such temporary authorization. *Texaco Inc.* v. *F.P.C.*, 290 F. 2d 149, 157.

We do not agree that the present matter is controlled by the decision in the *Texaco* case, *supra*, 290 F. 2d 149, 156, because the court's statement with respect to a company's right to file for a rate increase up to the initial contract rate was made with reference to a company's right to file after the issuance of a permanent certificate. In the instant case a permanent certificate has not been issued to Blanco covering the subject sale. We think that such difference is important. For, we are convinced that to protect adequately the public interest it is our duty to maintain the *status quo* pending disposition of the permanent certificate if we are to prevent potential damage that may arise from out of line price proposals in an applicant's contract.[4]

The Commission finds:

The assignments of error and grounds for rehearing contained in Blanco's application for rehearing filed January 26, 1962, set forth no new facts or principles of law which were not fully considered by the Commission in its letter order of December 28, 1961, or which having now been considered warrant any change or modification of that order.

The Commission orders:

Blanco's application for rehearing of the Commission's letter order of December 28, 1961 herein, filed on January 26, 1962, is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

ROBERT P. WILSON, PROJECT NO. 2279

ORDER DISMISSING APPLICATION FOR PRELIMINARY PERMIT

(Issued February 23, 1962)

Application was filed September 20, 1960, by Robert P. Wilson, of Taylorsville, California, for a preliminary permit under Section 4(f) of the Federal Power Act (hereinafter referred to as the Act) for proposed Project No. 2279 to be located on the upper reaches of Indian Creek and its tributaries Hungry Creek, Antelope Creek, Little Antelope Creek, and other—all ultimately tributary to North Fork of Feather River.

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[3] The final proviso in Blanco's acceptance, read in the light of the italicized language in its letter, can be interpreted only to reserve the right to file for increases during a period subsequent to that governed by the temporary authorization. We note additionally that we do not recognize the right of an applicant to modify the conditions which are set forth in the certificate tendered by the Commission.

[4] Among existing contracts which may be triggered or for which the proposed rate may serve as a basis for a price redetermination at a higher rate are the gas purchase contracts of Tennessee Gas Transmission Company and Texas Eastern Transmission Company in Texas District No. 4. See The Atlantic Refining Company's FPC Gas Rate Schedule No. 5; Phillips Petroleum Company (Operator), *et al.* FPC Gas Rate Schedule No. 20; and Pauley Petroleum, Inc. (Operator), *et al.* FPC Gas Rate Schedule No. 1.

The proposed project would be in the vicinity of Taylorsville, Crescent Mills, and Greenville, California, would lie enterly within Plumas County, California, and would affect lands of the United States within the Plumas National Forest.

As described in the application, the proposed project would consist of three dams on Indian Creek and their resultant reservoirs, three tunnels aggregating about 18,000 feet in length, and three powerhouses with an aggregate installed capacity of approximately 40,000 horsepower. The uppermost reservoir, which would flood a portion of the valley of Indian Creek and an area known as Antelope Valley at the confluence of the Antelope and Little Antelope Creeks, would provide the necessary storage for the two run-of-river downstream developments.

According to the application, power developed by the proposed project would be used, in part, in mining, smelting, refining and manufacturing operations, and for the use of persons, public agencies, farms, and corporations supplying power within the area of northern California.

By letter dated January 12, 1962, we were informed by the Chief, Forest Service, of the receipt by that Service of an application for special-use permit filed by the California Department of Water Resources (Department) for construction of the Antelope Valley Dam and Reservoir which would be primarily a public recreation project, including fishery enhancement. The Department's reservoir would occupy a considerable portion of Applicant's uppermost reservoir storage lands on Indian Creek as proposed in the application for Project No. 2279. By letter dated January 18, 1962, the Department's Director of Water Resources, in requesting early Commission disposition of the application for Project No. 2279, pointed out that the Antelope Valley Dam and Reservoir "was authorized by the Legislature in 1957, acquisition of the required private land was completed in 1959, funds for construction were included in a bond issue authorized by the Legislature in 1959 and ratified by a general election in 1960, water-right applications were assigned [by the State to the Department] in 1961, and construction of the project is scheduled to commence in April 1962."

The Chief, Forest Service, also requests that we make an early disposition of the application for Project No. 2279, and states that it considers it to be in the public interest and consistent with the purposes for which the Plumas National Forest was created to issue the special-use permit applied for by the Department and has requested that we either vacate the power withdrawal for Project No. 2279 or concur in the Forest Service proposal to issue a special-use permit to the Department, containing such conditions as we may specify as necessary for power purposes. The Department has advised the Forest Service that it is willing to accept a special-use permit conditioned on the applicability of Section 24 of the Federal Power Act preserving the power values of the lands of the United States. In the event power is developed later in connection with the Department's project, such development will of course be subject to licensing under the Federal Power Act.

Public notice of the application was followed by the filing of protests and petitions to intervene in this proceeding by Pacific Gas and Electric Company, the County of Plumas, California, and the Department of Water Resources, State of California. Permission to intervene was granted by Commission orders issued January 10, 1961, June 30, 1961 and June 9, 1961, respectively.

In view of the definite proposal of the Department to proceed immediately with development of its Antelope Valley Dam and Reservoir for recreation and possibly for later water-power development; and the desire of the Forest Service to have this reservoir constructed within the National Forest, *the Commission finds:*

736-330—64——28

It is appropriate and in the public interest in carrying out the provisions of the Federal Power Act that the application for preliminary permit for proposed Project No. 2279 be dismissed.

The Commission orders:

The aforesaid application is dismissed.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CITIES SERVICE GAS COMPANY, DOCKET NOS. CP60-32 AND CP62-82

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 26, 1962)

On September 27, 1961, as supplemented on November 22, 1961, and January 12, 1962, Cities Service Gas Company (Applicant) filed in Docket No. CP62-82 an application for disclaimer of jurisdiction or, in the alternative, for a certificate of public convenience and necessity pursuant to Section 7(c) of the Natural Gas Act authorizing the installation and operation of pipeline taps and block gates on Applicant's Kansas City-Hugoton pipeline at the intake side of Applicant's Hugoton Compressor Station in Grant County, Kansas, to enable Applicant to deliver natural gas to Cities Service Helex, Inc. (Helex), all as more fully set forth in the application as supplemented.

Helex proposes to construct and operate a field processing plant adjacent to Applicant's presently existing Hugoton Compressor Station and connected to Applicant's Hugoton Field pipeline system. Applicant has agreed to deliver to Helex for processing in its plant volumes of natural gas on an interruptible basis as such volumes are available to Applicant. From the volumes of gas so delivered, Helex has the right to consume up to a maximum volume of 75 MMcf of gas in any 24-hour period for the purpose of extracting helium, liquid hydrocarbons, and other components of the natural gas so delivered. The volumes of natural gas remaining after such processing by Helex will be returned to Applicant at a point adjacent to the point of delivery by Applicant to Helex.

The extraction of helium, liquid hydrocarbons, and other components from the natural gas so delivered, together with the use of gas for fuel and incidental use in the plant, will necessarily result in Helex's redelivery to Applicant of a lesser volume of gas than it received. It is estimated by Applicant that this reduction will average approximately 60 MMcf of gas per day based on deliveries to Helex of approximately 500 MMcf of gas per day.

The contract between Applicant and Helex provides that Helex will pay Applicant an initial price of 20.8¢ per Mcf, with annual adjustments, for the net volumes of gas consumed in Helex's processing operations.

Helex has agreed with Applicant that in the operation of the processing plant the unit heating value of the gas redelivered to Applicant will be the same as the unit heating value of the gas delivered by Applicant to Helex. Helex further agreed with Applicant to return gas at the same pressure at which Applicant delivers it to Helex.

From the subject volumes of gas Helex proposes to extract crude helium, a crude stream of normally liquifiable higher hydrocarbons, and such volumes of nitrogen as may be required to enable Helex to fulfill its obligation with respect to the heat content of the gas redelivered to Applicant. The helium to be

extracted will be resold by Helex pursuant to its contract with the United States of America dated August 22, 1961. The mixed hydrocarbon product will be sold by Helex in a crude stream which will be transported by pipeline to refining facilities at another location. The refined hydrocarbon product will be either sold as liquified petroleum gas or used in petro-chemical processes.

The proposed facilities to be built by Cities Service Gas Company will cost $95,000 and will be financed from treasury cash.

Concurrently with the subject application, Applicant has submitted a study of its gas reserves. Based on this study, Applicant has requested that paragraph (F) of the order issued December 27, 1960, in Docket No. CP60-32 (24 FPC 1127) be eliminated. That paragraph requires that Applicant shall limit its total annual sales of natural gas to an amount approximately equal to the total demands served, as shown in line 43 of Exhibit No. 30 in Docket No. CP60-32, beginning with the calendar year 1961 and in each calendar year thereafter until Applicant makes a showing, satisfactory to the Commission, that such restriction should be eliminated or modified. Applicant has made a showing in the instant application that said restriction should be eliminated.

Due notice of the application for amendment in Docket No. CP60-32 was published in the Federal Register on January 19, 1962 (27 F.R. 598). No protest, petition to intervene or request for hearing thereon has been received.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 13, 1962, in Docket No. CP62-82, respecting the matters involved in, and the issues presented by, the application in this proceeding. No protest or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Cities Service Gas Company, a Delaware corporation having its principal place of business in Oklahoma City, Oklahoma, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order issued December 28, 1943, in Docket No. G-298 (4 FPC 471).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in Docket No. CP62-82, are to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued in Docket No. CP62-82 authorizing Cities Service Gas Company

to construct and operate the proposed facilities and to transport natural gas in interstate commerce as hereinbefore described, all as more fully described in the application as supplemented in said Docket No. CP62–82, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(C) The facilities authorized by paragraph (A) above shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 2 years from the date on which this order issues.

(D) The Commission's order issued on December 27, 1960, in Docket No. CP60–32 (24 FPC 1127) be and the same is hereby amended to rescind the restriction in service contained in paragraph (F) thereof.

(E) In all other respects said order issued on December 27, 1960, in Docket No. CP60–32 (24 FPC 1127) shall remain unchanged and in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

ALABAMA POWER COMPANY, DOCKET NO. E–6893

DETERMINATION OF PROPORTION OF ANNUAL CHARGES FOR HEADWATER BENEFITS

(Issued February 27, 1962)

By Commission order issued October 11, 1951 (10 F.P.C. 1423), an investigation was instituted pursuant to the provisions of the Federal Power Act, particularly Section 10(f) thereof, for the purpose of enabling the Commission to determine whether certain hydroelectric developments of Alabama Power Company (Company); namely, its Lay, Mitchell and Jordan developments, which are presently maintained and operated under licenses issued under the Act as Project Nos. 2146, 82 and 618, respectively, on the Coosa River are directly benefited by the construction and operation of the upstream Allatoona project of the United States and, if it so finds, to assess against the Company the equitable proportion of the annual charges for interest, maintenance, and depreciation on the Allatoona headwater improvement which the Company should pay to the United States. In addition, under the provisions of Section 10(f) of the Act, the Company is required to pay to the United States the cost of making such determination as fixed by the Commission.

The Allatoona headwater improvement is located on the Etowah River, a tributary of the Coosa River, near Cartersville, Georgia, and was constructed by the Corps of Engineers, Department of the Army. Completed in 1950, the Allatoona project is operated for the primary purposes of flood control and power.

The installed capacity of the Company's Lay, Mitchell and Jordan developments is 64,800 kilowatts, 72,500 kilowatts and 100,000 kilowatts, respectively.

By determinations issued August 18, 1954 (13 FPC 1317), August 9, 1956 (16 FPC 827), and October 27, 1959 (22 FPC 749), the Commission determined the equitable proportion of the above-stated annual charges for the years 1950 through 1957 and fixed costs of making such determinations.

The investigation made for the calendar years 1958 through 1960, discloses that the regulation of flows by the Allatoona headwater improvement caused an increase in generation at the Company's three afore-mentioned downstream developments totaling 111,229,125 kilowatt-hours during this period. During the period covered by this investigation, the operation of the Allatoona project did not affect the dependable capacity of the Lay, Mitchell and Jordan developments.

The Commission determines:

The equitable proportion of the annual charges for interest, maintenance and depreciation on the Allatoona headwater improvement to be paid by Alabama Power Company to the United States for benefits directly received for the calendar years 1958 through 1960 is as follows:

Calendar year	*Amount*
1958	$56,417
1959	53,916
1960	57,888
Total	168,221

The Commission finds:

The cost to the Commission of making the determination herein is $6,560.

The Commission orders:

Payment to the Commission of the sum of $168,221 and $6,560 for the above-stated purposes shall be made by Alabama Power Company within 30 days from the date of issuance of this determination.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CAROLINA POWER & LIGHT COMPANY, PROJECT NO. 2206

ORDER APPROVING REVISED EXHIBIT L DRAWINGS

(Issued February 27, 1962)

On December 13, 1961, Carolina Power & Light Company, licensee for major Project No. 2206, filed for Commission approval two revised Exhibit L drawings relating to the Tillery development of the project. The filing was pursuant to Article 5 of the license for the project.

The revised drawings reflect corrections of minor errors appearing in the Exhibit L drawings now parts of the license, but do not reflect any changes in the project structures.

The Commission finds:

The following-described revised Exhibit L drawings conform to the Commission's rules and regulations and should be approved as part of the license for the project, and the Exhibit L drawings (FPC Nos. 2206-35 and 2206-36), now parts of the license, and which are superseded, should be eliminated from the license—all as hereinafter provided:

Exhibit L (Revised) sheet 2 of 12 (FPC No. 2206-39) entitled "Development Expansion—Plans"

Exhibit L (Revised) sheet 3 of 12 (FPC No. 2206-40) entitled "Development Expansion—Cross-Section"

The Commission orders:

The revised Exhibit L drawings described in the above finding as conforming to the Commission's rules and regulations are approved as parts of the license for Project No. 2206, and the exhibits described in the same finding as being superseded are eliminated from the license for the project.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TENNESSEE NATURAL GAS LINES, INC., DOCKET NO. CP61-197; TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. CP62-93

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 27, 1962)

On October 30, 1961, as amended on November 16, 1961, Tennessee Natural Gas Lines, Inc. (Tennessee Natural), filed in Docket No. CP61-197 a motion to amend an order issuing a certificate of public convenience and necessity, and on October 12, 1961, as supplemented and amended on November 2, 1961, Tennessee Gas Transmission Company (Tennessee) filed in Docket No. CP62-93 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity, both as hereinafter described, and as more fully set forth in the motion and application.

Tennessee Natural in the subject motion requests amendment of the order of the Commission issued April 10, 1961, in Docket No. CP61-197 (which order authorized Movant to sell up to 20,800 Mcf of interruptible gas per day to Ford Motor Company (Ford), a direct industrial customer, for use in its glass plant in Nashville, Tennessee) by authorizing Tennessee Natural to sell to Ford 15,500 Mcf of interruptible gas per day and 5,300 Mcf of firm gas per day, instead of 20,800 Mcf of interruptible gas per day. The change is necessary due to an expansion at the Ford plant. In Docket No. CP61-27 Tennessee Natural has a pending application to make the same conversion on a long-term basis, which application is dependent on Tennessee's expansion pending in Docket No. CP60-94. The motion proposes that the conversion be effective for the period ending November 30, 1962.

Tennessee seeks authorization in Docket No. CP62-93 to render interim additional service until November 30, 1962, to three of its existing customers as follows (Mcf per day at 14.73 psia):

Customers	Presently authorized long-term maximum contract quantity	Proposed interim service	Total long-term and interim service
Inland Gas Corporation	40,800	5,100	45,900
United Gas Pipe Line Company:			
Oxford	5,945	1,055	7,000
Shaw, *et al.*	8,318	1,166	9,484
Tennessee Natural Gas Lines, Inc.	111,364	5,300	116,664
Total	166,427	12,621	179,048

These customers are Tennessee's only existing customers that will not have sufficient gas supply to meet their 1961–62 winter requirements. The proposed interim service will be rendered under Tennessee's FPC Gas Rate Schedules on file with the Commission, and can be rendered without additional facilities.

Temporary authorization to render the service proposed in Docket No. CP62–98 was granted to Tennessee on December 11, 1961.

Due notice of the application for amendment in Docket No. CI61–197 was published in the Federal Register on January 24, 1962 (27 F.R. 705). No protests, petitions to intervene or requests for hearing have been received.

Pursuant to due notice a public hearing was held in Docket No. CP62–93 in Washington, D.C., on February 15, 1962, respecting the matters involved in and the issues presented by the application therein. No protest or petition to intervene has been received. Staff counsel moved orally at the hearing that intermediate decision procedure be omitted and that the Commission render a decision in Docket No. CP62–93 pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act and the public convenience and necessity require that the Commission's order issued on April 10, 1961, in Docket No. CP61–197 (25 FPC 717) be amended as hereinafter ordered.

(2) Applicant, Tennessee Gas Transmission Company, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order issued July 15, 1947, in Docket No. G–910 (6 FPC 777).

(3) The sales of natural gas proposed in Docket No. CP62–93 as hereinbefore described, and as more fully described in the application in Docket No. CP62–93, will be made in interstate commerce, subject to the jurisdiction of the Commission, and are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The proposed sales and delivery of natural gas by Tennessee Gas Transmission Company in Docket No. CP62–93 are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Tennessee's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of such Regulations.

(6) Tennessee is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(7) A request during the public hearing in Docket No. CP62–93 by staff counsel for omission of the intermediate decision procedure therein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) The order of the Commission issued on April 10, 1961, in Docket No. CP62–197 be and the same is hereby amended to authorize Tennessee Natural Gas Lines, Inc., to sell and deliver to Ford Company up to 15,500 Mcf of interruptible gas per day and 5,300 Mcf of firm gas per day in lieu of the

previously authorized quantity of 20,800 Mcf of interruptible gas per day until November 30, 1962. Beyond November 30, 1962, the service shall return to 20,800 Mcf per day of interruptible service.

(B) In all other respects the order issued on April 10, 1961, in Docket No. CP61-197 shall remain unchanged and in full force and effect.

(C) A certificate of public convenience and necessity be and the same is hereby issued authorizing Tennessee Gas Transmission Company to make the proposed sales and deliveries, as hereinbefore described and as more fully described in the application in Docket No. CP62-93, until November 30, 1962, upon the terms and conditions of this order.

(D) The certificate issued by paragraph (C) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of such Regulations.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

THE WESTERN COLORADO POWER COMPANY, PROJECT NO. 400

ORDER FURTHER AMENDING LICENSE (MAJOR)

(Issued February 27, 1962)

Application was filed August 1, 1960 and supplemented August 15, 1960 by The Western Colorado Power Company, licensee for major Project No. 400, for further amendment of its license for the project located on Lake Fork and Howard Fork of San Miguel River in San Miguel County, Colorado, and affecting lands of the United States within the Uncompahgre National Forest.

The presently licensed project consists of three constructed power developments designated as Tacoma, Ames and Ilium.

The amendment sought would exclude from the license the Ilium power development works consisting of diversion dams, flume, surge tank, penstock, powerhouse, operators' cottages, and other appurtenant works of the Ilium power development, including a segment of the (T-3) 11 kv line, between Station 45+44 and Station 367+27. Another segment of the (T-3) line, would be relocated on a new center line between the Town of Ilium and the Town of Telluride, Colorado.

The application states that the Ilium plant has not been in service since July 1959 when a portion of the wood box flume collapsed and further operation became impossible. Continued operation would require, according to the application, a new flume and semiautomatic controls, the cost of the installation of which would render the operation of the plant economically infeasible, and, moreover, other facilities belonging to the licensee are sufficient to supply all power demands within the licensee's territory.

Elimination from the license of the Ilium plant with its 1,600 horsepower capacity will reduce the annual administration charges, under the license, based upon installed horsepower capacity, from 16,000 to 14,400 horsepower. Such elimination will also reduce the lands of the United States occupied by the project by approximately 47.45 acres. By the removal of the afore-mentioned 11 kv (T-3) line, 1.909 miles of 100-foot right-of-way on lands of the United States will be eliminated, while the relocation of the 12 kv (T-3) line will increase the lands of the United States occupied by transmission lines by 0.839 mile of 100-foot right-of-way.

By letter dated August 10, 1961, the Chief, Forest Service, acting for the Secretary of Agriculture, who has supervision over the Uncompahgre National Forest, has advised us that the lands formerly occupied by the Ilium development have been restored to a condition satisfactory to the Service.

The Commission finds:

(1) The license, further amended as hereinafter ordered, will not interfere or be inconsistent with the purposes for which the Uncompahgre National Forest was created or acquired, and is in the public interest.

(2) Public notice has been given of the filing of the application. No protests have been received.

(3) The authorized installed capacity of the project for the purpose of computing the capacity component of the administrative annual charge is 14,400 horsepower and the annual charge for reimbursing the United States for the costs of administration of Part I of the Federal Power Act, based upon such capacity, as hereinafter provided, is reasonable.

(4) The decreased amount of annual charges to be paid under the license, as hereinafter fixed and specified, for the purpose of recompensing the United States for the use, occupancy, and enjoyment of its lands, including those used for transmission line rights-of-way, is reasonable.

(5) The following described exhibits filed as part of the application as supplemented conform to the Commission's rules and regulations and should be approved as part of the license for the project and the exhibits hereinafter decribed as being superseded in whole or in part, should be eliminated from the license or revised as hereinafter indicated and as so-revised should be reapproved as part of the license for the project—all as hereinafter provided:

Supplemental Exhibit J (FPC No. 400–46) showing the General-System Map of The Western Colorado Power Company, superseding Exhibit J (FPC No. 400–17); and

Amended Exhibit K (FPC No. 400–47) showing the relocation of the 12 kv (T–3) line, and superseding Exhibit K (FPC No. 400–24) insofar as it shows the 11 kv (T–3) line.

(6) Amended Exhibit K, sheet 5 of 7 (FPC No. 400–22) showing location of dams, powerhouses, lands and center line of pipe and power lines of the Ilium Plant, and Amended Exhibit L (FPC No. 400–29), showing the Ilium Project improvements to be removed—both parts of the license for the project—should be eliminated from the license as hereinafter provided.

(7) Amended Exhibit L, sheet 4 of 5 (FPC No. 400–28) showing general design drawings of Tacoma-Ames-Ilium Project of The Western Colorado Power Company, now part of the license for the project, should be revised so as to delete therefrom the portion showing the Ilium Station and as so-revised should be reapproved as part of the license for the project as hereinafter provided.

The Commission orders:

(A) The exhibits described in finding (5) above as conforming to the Commission's rules and regulations are approved as part of the license for Project No. 400 and the exhibits described in the same finding as being superseded in whole or in part, are eliminated from the license for the project to the extent indicated.

(B) The exhibits described in finding (6) above are eliminated from the license for the project.

(C) The exhibit described in finding (7) above revised by Commission staff to delete therefrom the portion showing the Ilium Station is reapproved as part of the license for the project.

(D) The license for Project No. 400, as amended, is further amended, effective as of August 10, 1961, as follows:

PARAGRAPH I. The following part of subparagraph (b) of Article 2 of the license is further amended to read:

(b) All project works, consisting of two constructed power plants designated as Tocamo and Ames plants with appurtenant dams, reservoirs, water conduits, and equipment; and six transmission lines as follows: one from Tacoma power plant to Silverton substation; one from Ames power plant to station 348+38 (T–1) line); one between Ames and Ilium (T–2 line); one from Ilium to Telluride (T–3 line); and one from Ames power plant to the Burro Bridge Sectionalizing Station, and one from Tacoma to Durango; the location and character of said project works being more fully shown and described by the exhibits hereinbefore listed, and certain other exhibits which are designated and described as follows:

PARAGRAPH II. Article 20 of the license is further amended to read:

Article 20. The Licensee shall pay to the United States the following annual charges:

(i) for the purpose of reimbursing the United States for the costs of administration of Part I of the Act, one (1) cent per horsepower on the authorized installed capacity (14,400 horsepower), plus two and one-half (2½) cents per 1,000 kilowatt-hours of gross energy generated by the project during the calendar year for which the charge is made;

(ii) For the purpose of recompensing the United States for the use, occupancy, and enjoyment of its lands, excluding those used for transmission line right-of-way, $168.52; and

(iii) For the purpose of recompensing the United States for the use, occupancy and enjoyment of its lands used for transmission line right-of-way only, $213.56.

(E) This amendment in the manner set out above shall not operate to alter or amend the license in any other respect, and shall not in any way constitute a waiver of any other part, provision or condition of the license as heretofore amended.

(F) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313(a) of the Federal Power Act and failure to file such an application shall constitute acceptance of this amendment of license. In acknowledgment of the acceptance of this amendment of license, it shall be signed for the Licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NEW ENGLAND POWER COMPANY

ORDER ACCEPTING RATE SCHEDULES FOR FILING, DIRECTING THE SUBMISSION OF DATA, AND DIRECTING STAFF INVESTIGATION

(Issued February 28, 1962)

The New England Power Company (Nepco) Boston, Massachusetts, filed the rate schedules in issue on December 12, 1961. By agreement with the company the effective date was postponed in order to permit the Commission to make a more intensive study of the filings than would otherwise have been

possible.[1] The Commission has also directed staff to make a field investigation to aid it in its consideration of the proper action to take on these filings. Such an investigation has been made, although on a necessarily limited basis, both because of lack of availability of staff and because Nepco's revenue needs appear to be such as to require prompt action upon the filings.

This order accepts without suspension and formal hearing a number of revised rate schedules of Nepco increasing that company's present demand and energy charges for firm power and energy service to eight wholesale customers by an estimated 2.9%, or $1,545,000 per annum for all purchasers. In view of the fact that some of Nepco's claimed costs are so high as to raise question as to their allowability, our reasons for doing so should be stated at the outset.

At present Nepco and its corporate affiliates in the New England Electric System incur substantial costs in connection with a number of small, scattered, and inefficient steam electric generating sources located throughout the New England System.[2] These facts have been recognized by Nepco management which has been engaged in intensive efforts in recent years to bring down its costs of power supply. However, for purposes of this order we recognize the foregoing to be the situation in which Nepco now finds itself. Our allowance of the proposed rate increase will prospectively assist Nepco in meeting its power supply problems. The increased revenues to be derived under Nepco's revised rates and charges will afford the company an opportunity to continue, accelerate and enlarge its current program for replacement of these small generating sources with larger and more efficient units, and to increase the coordination of its electric utility facilities with those of other systems.

Nepco's representatives have advised the Commission's staff that during 1962, and possibly 1963, the rate increases we are permitting to go into effect will be absorbed within the New England Power System and will not affect consumer rates.

The long-range interests of the consumers of New England, including the industries which provide employment in the area, require acceleration of Nepco's progress in reducing the cost of producing power. For that reason we think the public interest will best be served by affording Nepco this opportunity to use the proceeds of the rate increase to improve system efficiency. For that reason we find it unnecessary to consider matters which would be significant were we here proposing, after formal investigation and hearing pursuant to Section 205 of the Federal Power Act, to disallow certain of Nepco's claimed costs and to prescribe the company's rates and charges for the future. Our rate regulatory jurisdiction over Nepco is a continuing one (Section 206 of the Federal Power Act). In the exercise thereof, we are directing Nepco to submit additional cost and revenue data showing its cost of rendering firm wholesale electric service for the 1962 calendar year, adjusted for the rate increases for the full year. Also, we have directed the Commission's staff to undertake a more comprehensive field investigation and study of Nepco's electric utility operations, with special emphasis upon inter-system connections and other projected power supply arrangements looking to further coordination of company's facilities with those of other systems. The information thus made available will afford the Commission a basis upon which to consider the need for any additional action relative to Nepco's services and rates.

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[1] Nepco's December 12, 1961, filing was an amendment of an earlier rate schedule filing tendered April 25, 1961. The requested effective date of March 1, 1962, was agreed to by Nepco following conferences with the Commission's staff.

[2] Statistics of these plants are set forth in detail in Appendix A attached hereto.

The proposed rate schedules have been designated in the files of the Commission as follows:

Rate schedule designation	*Purchasing utility*
Supplement No. 2 to Nepco's Rate Schedule FPC No. 105.	Fitchburg Gas and Electric Light Company.
Supplement No. 2 to Nepco's Rate Schedule FPC No. 112.	Granite State Electric Company.
Supplement No. 1 to Nepco's Rate Schedule FPC No. 116.	Town of Littleton, New Hampshire.
Supplement No. 2 to Nepco's Rate Schedule FPC No. 111.	Lynn Electric Company.
Supplement No. 2 to Nepco's Rate Schedule FPC No. 117.	Massachusetts Electric Company.
Supplement No. 11 to Nepco's Rate Schedule FPC No. 99.	Merrimack-Essex Electric Company.
Supplement No. 2 to Nepco's Rate Schedule FPC No. 106.	The Narragansett Electric Company.
Supplement No. 1 to Nepco's Rate Schedule No. 115.	Suburban Electric Company.[1]

[1] With the exception of Fitchburg Gas and Electric Light Company all of the above-designated companies are corporate affiliates of Nepco in the New England Electric System.

Protests or objections to the revised schedules were submitted by a number of persons and municipalities, including several municipalities which purchase electric power and energy from certain of the above-mentioned direct customers of Nepco. The Commission's staff, as already noted, conducted a field examination of Nepco's supporting cost and operating data.

Facts currently before the Commission indicate that Nepco's proposed increased rates and charges will produce revenues sufficient to cover its cost of service, including a return of approximately 6% upon net investment allocated to Nepco's firm power wholesale service. This rate of return, based upon a 1960 test year, was determined in accordance with the principles customarily applied by the Commission in computing cost of service, rate base, and rate of return. The computed rate base includes average net investment in Nepco's power pool facilities, i.e., production plant, transmission plant (exclusive of lines, substations, and other facilities used solely for distribution), and an allocated share of general plant. Working capital allowance includes an amount of cash working capital allocable to Nepco's power pool, together with prepayments, less 50% of Nepco's federal income tax accruals, including deferred federal income tax credits arising from accelerated depreciation practices pursuant to Section 168 of the Internal Revenue Code of 1954. The federal income tax allowance in Nepco's cost of service reflects depreciation expense, other than accelerated, in excess of book depreciation, but exceeds actual income taxes for the period by the amount of deferred tax resulting from accelerated amortization.

We note that Nepco's treatment of deferrals of income taxes conforms to certain prior Commission precedents. We do not necessarily endorse such treatment in principle and reserve the right to reexamine that matter, but if there is any change in Commission policy in respect to the treatment of income tax deferrals it will not be applied retrospectively.

Included among Nepco's claimed costs of service are fixed and operating expenses in connection with eight small steam electric generating stations owned by three corporate affiliates of Nepco: Merrimack-Essex Electric Company, Massachusetts Electric Company, and Lynn Electric Company. Pursuant to contractual arrangements among Nepco and its affiliates, Nepco pays all fixed

and operating costs associated with those generating stations, including income and other taxes, and allowances for a 6% return upon a net investment base. In return for that payment Nepco is contractually entitled to the entire output of all plants, an aggregate of 205,500 kw under 1961 ratings.[2] Most of the generating units located in those stations have been in service for many years, and some are of questionable value in Nepco's rendition of electric utility service to the public. For example, during calendar years 1960 and 1961, two of Merrimack-Essex Electric Company's generating stations failed to produce any of the electric energy which Nepco supplied to its customers. Since 1959 those stations (Lawrence and Lowell) have been maintained as cold standby generating reserves, requiring periods of up to 30 days to be made serviceable as hot or ready generating reserves. Merrimack-Essex Electric Company's Salem plant was placed in cold reserve during June 1961. Collectively, these three stations are currently rated by Nepco at 50,000 kw gross capability.

By present technological and operating standards, Merrimack-Essex Electric Company's steam electric generating stations—Lawrence, Lowell, Salem, Gloucester, Haverhill, and Newburyport—and the low pressure units in Massachusetts Electric Company's Webster Street Station are thermally inefficient and generally have high costs. Appendix A hereto sets forth in summary form Nepco's claimed costs in connection with such steam electric generating station of its corporate affiliates during the calendar years 1960 and 1961.

Corrective measures will require the outlay of substantial amounts of capital by Nepco and its corporate affiliates in the New England Electric System. We are advised that current construction programs contemplate replacement of the generating capacity made available to Nepco by its affiliates with larger and more efficient units now under construction; expansion and strengthening of transmission and distribution facilities of Nepco and its affiliates; and enlargement and further development of interconnections between Nepco and its affiliates and nonaffiliated electric untility systems.

Nepco currently owns and operates fourteen hydroelectric generating stations having a total installed capability of 484,000 kw, and one steam electric generating station (Salem Harbor) with an installed capability of 322,000 kw. Nepco also has under construction a second steam electric generating station at Brayton Point, Massachusetts, which, as planned, will ultimately have a capability of approximately 1,000,000 kw. One 245,000 kw generating unit in the Brayton Point station is scheduled for completion in 1963 and a second 245,000 kw generating unit is scheduled for completion in 1964. Nepco's current firm power purchase arrangements total 437,000 kw. Included among these sources of supply are Nepco's three affiliates (Merrimack-Essex Electric Company, Massachusetts Electric Company, and Lynn Electric Company), and five other companies (Montaup Electric Company, Holyoke Power and Electric Company, Public Service Company of New Hampshire, Boston Edison Company, and Yankee Atomic Electric Company). In July of the current year Nepco's proposed 230 kv interconnection with the Niagara Mohawk Power Corporation will be completed.

Based upon projected loads and sources of generating capacity available to Nepco, including the above purchase arrangements, Nepco's system planning as reported to this Commission results in the following peak hour system reserves:

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[2] Nepco estimates that by the end of 1964 these eight plants will be down-rated to an aggregate capability of approximately 130,000 kw for system planning purposes.

	1961	1962	1963
	Kw	*Kw*	*Kw*
Capacity	1,243,000	1,333,000	1,452,000
Load	1,117,000	1,192,000	1,317,000
Reserve	126,000 (11.3%)	141,000 (11.8%)	135,000 (10.3%)

The Commission further finds:

It is necessary and appropriate for the purposes of the Federal Power Act, particularly Sections 205, 206, 307, and 309 thereof, that Nepco's revised rate schedules, as designated above, be accepted to become effective as filed rate schedules under that Act on and after March 1, 1962; that Nepco be directed to submit cost and revenue data for the 1962 calendar year, adjusted for the rate increases for the full year; and that the Commission's staff undertake a field examination and study of Nepco's electric utility operations, including the company's present electric loads and sources, projected electric loads and sources, present interconnections with other electric systems, and possible additional interconnections which Nepco might consider in order to improve its system performance.

The Commission orders:

(A) Nepco's revised rate schedules, as designated above, are hereby accepted for filing pursuant to Section 205(d) of the Federal Power Act and Section 35.3 (c) of the Commission's Regulations under that Act, to become effective as filed rate schedules of Nepco on March 1, 1962.

(B) On or before March 1, 1963, Nepco shall show its cost of rendering service under the revised rate schedules, calculated in accordance with applicable Commission rulings and utilizing, among other things, as the test period the calendar year 1962 adjusted for the rate increases for the full year, a prudent net investment rate base, a fair rate of return thereon, and electric operating revenues collected during the test period.

(C) The foregoing showing shall not preclude or limit any additional showing by Nepco, and shall be without prejudice either to any future action by the Commission or its staff or to any future position Nepco may wish to take as to the significance of, or conclusions to be drawn from, the above factual showing.

(D) The foregoing showing shall be submitted in writing with sufficient copies to provide this Commission with six copies and to provide each State Commission affected with a like number of copies.

APPENDIX A

Steam contract summary 12 months ending December 31, 1960

	Merrimack-Essex Electric Company						Total M–E	Webster Street, Mass. Elec.	Lynn Elec., 9 months	Total
	Gloucester	Haverhill	Lawrence	Lowell	Newbury-port	Salem				
Total gross capability (kw)	4,000	10,000	11,500	18,000	6,000	20,500	70,000	76,000	59,500	205,500
19 Months' Billing										
Fixed payment	$38,829	$103,394	$56,247	$243,505	$42,826	$127,694	$612,495	$985,200	$360,000	$1,957,695
F.I.T.	4,641	11,413	3,966	22,049	5,002	14,727	61,798	305,004	127,503	494,305
Municipal tax	27,572	81,984	56,688	165,864	20,640	97,057	449,805	432,903	413,217	1,295,925
Franchise tax	980	2,409	834	4,656	1,054	3,115	13,048	33,996	14,247	61,291
Payroll overheads	11,117	31,665	3,863	8,700	12,226	31,662	99,233	184,745	68,976	352,954
Steam sales credit, fixed	(9,910)						(9,910)			(9,910)
Distribution plant, production								5,004		5,004
Total fixed charges	$73,229	$230,865	$121,598	$444,774	$81,748	$274,255	$1,226,469	$1,946,852	$983,943	$4,157,264
Fuel costs	45,628	149,982	(1,034)	229	48,214	36,253	279,272	1,394,794	565,810	2,239,876
Production costs, except fuel	74,279	216,182	40,944	66,299	82,390	213,335	693,429	1,294,122	485,254	2,472,805
Steam sales credit, variable	(29,881)						(29,881)		(23,466)	(53,347)
Building heating credit	(1,044)	(3,843)			(840)	(5,670)	(11,397)	(993)		(12,390)
Other fuel used credit								(22,529)		(22,529)
Boiler maintenance credit								(60)		(60)
Total variable charges	88,982	362,321	39,910	66,528	129,764	243,918	931,423	2,665,334	1,027,598	4,624,355
Total billing	162,211	593,186	161,508	511,302	211,512	518,173	2,157,892	4,612,186	2,011,541	8,781,619
Net generation (million kwh)	0.202	4.295			1.148	0.398	6.041	214.627	82.543	303.214
Fixed charges ($/kw-yr.)	$18.31	$23.09	$10.57	$24.71	$13.62	$13.38	$17.50	$25.62	$22.05	$21.83
Variable charges (mills/kwh)	440.5	84.4			113.0	612.9	154.2	12.4	12.4	15.3

Source: New England Power Company.

APPENDIX A—Continued

Steam contract summary 12 months ending December 31, 1961

	Merrimack-Essex Electric Company						Total M-E	Mass. Elect. Co.	Lynn Elect. Co.	Total
	Gloucester	Haverhill	Lawrence	Lowell	Newbury-port	Salem				
Total gross capability (kw)	4,000	10,000	11,500	18,000	6,000	20,500	70,000	76,000	59,500	205,500
9 Months Billing—3 Months Estimated (thousands)										
Fixed payment	$38	$100	$53	$233	$41	$118	$583	$985	$480	$2,048
F.I.T.	4	10	3	18	4	13	52	305	170	527
Municipal tax	28	84	54	171	21	100	458	433	610	1,501
Franchise tax	1	2	1	3	1	3	11	34	19	64
Payroll overheads	10	32	4	7	12	19	84	186	20	290
Steam sales credit, fixed	(10)						(10)			(10)
Distribution plant, production								5		5
Total fixed charges	$71	$228	$115	$432	$79	$253	$1,178	$1,948	$1,299	$4,425
Fuel costs	53	204			60	18	335	1,228	707	2,270
Production costs, except fuel	63	200	32	54	83	138	570	1,594	836	3,000
Steam sales credit, variable	(32)						(32)		(39)	(71)
Building heating credit	(1)	(5)			(1)	(4)	(11)	(1)		(12)
Other fuel used credit										
Boiler maintenance credit										
Total variable charges	83	399	32	54	142	152	862	2,821	1,504	5,187
Total billing	154	627	147	486	221	405	2,040	4,769	2,803	9,612
Net generation (million kwh)	0.258	5,761			1.302		7.321	231.482	117.086	355.889
Fixed charges ($/kw-yr.)	$17.75	$22.80	$10.00	$24.00	$13.17	$12.34	$16.83	$25.63	$21.83	$21.53
Variable charges (mills/kwh)	321.7	69.3			109.1		117.7	12.2	12.8	14.6

Source: New England Power Company.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NEW YORK STATE NATURAL GAS CORPORATION; TEXAS EASTERN TRANSMISSION CORPORATION, DOCKET NO. CP62-102

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued February 28, 1962)

On October 19, 1961, New York State Natural Gas Corporation (New York Natural) and Texas Eastern Transmission Corporation (Texas Eastern) filed in Docket No. CP62-102 a joint application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the exchange of natural gas and the construction and operation of facilities for such exchange, all as more fully set forth in the application.

New York Natural owns four gas wells in Monroe Township, Bedford County, Pennsylvania, an area in which it has no transmission pipeline of its own. In order to market the gas produced from these wells, New York Natural and Texas Eastern have entered into an exchange agreement dated August 16, 1961, in which New York Natural agrees to construct and operate approximately 7.1 miles of 6-inch pipeline from its Bedford County producing area to a point of connection with Texas Eastern's 20-inch and 24-inch transmission pipelines near Rock Hill Church, approximately three miles west of Mattie in Monroe Township, Bedford County, Pennsylvania, and to construct and operate a measuring station at the connection. New York Natural proposes to deliver the Bedford County production into Texas Eastern's lines at said point up to a maximum of 10,000 Mcf of gas in any 24-hour period unless otherwise agreed upon by the parties. The agreement further provides that Texas Eastern will simultaneously return equivalent daily quantities of gas to New York Natural at an existing interconnection of their respective pipeline systems in Greene County, Pennsylvania; or with prior consent of the parties, deliveries may be made at any other point of connection between their pipeline systems.

New York Natural estimates the total cost of the pipeline and measuring station to be $155,694, which will be financed from funds on hand.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 21, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, New York State Natural Gas Corporation, a New York corporation having its principal place of business in Pittsburgh, Pennsylvania, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 27, 1942, in Docket No. G-312 (3 FPC 844).

(2) Applicant, Texas Eastern Transmission Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order issued October 11, 1947, in Docket No. G-880 (6 FPC 148).

(3) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the exchange of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by New York Natural are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) Applicants are able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(5) The construction and operation of the facilities and the exchange of natural gas as proposed by Applicants are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(6) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations, and further, that the time within which construction of the facilities authorized by this order should be completed and said facilities placed in actual operation should be fixed at 30 days from the date on which this order issues.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing New York State Natural Gas Corporation to construct and operate the facilities hereinbefore described, and New York State Natural Gas Corporation and Texas Eastern Transmission Corporation to exchange natural gas, all as more fully described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The time within which the facilities shall be completed and placed in regular operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act is hereby fixed at 30 days from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SOUTH GEORGIA NATURAL GAS COMPANY, DOCKET NO. CP60-11

ORDER DENYING IN PART AND GRANTING IN PART PETITION FOR MODIFICATION OF CERTIFICATE

(Issued February 28, 1962)

On January 10, 1962, South Georgia Natural Gas Company (Petitioner) filed a petition to modify the certificate of public convenience and necessity granted

to the petitioner herein by order issued on January 12, 1961, so as to extend the time for completion of the facilities authorized until August 1, 1962, and so as to delete paragraph (D) of said order.

Said certificate authorized the construction and operation of certain facilities consisting of pipeline extensions, laterals and meter and regulator stations for the sale and delivery of natural gas to the cities of Ocilla and Sylvester, Georgia for resale to the public.

Paragraph (D) of the Commission's order granting said certificate reads as follows:

> This certificate shall not be effective as to the sales and the additional facilities necessary to the consummation of such sales to either of said cities of Sylvester and Ocilla, Georgia, unless, and until the said city shall have presented proof, to this Commission and to South Georgia, that the necessary bonds for the construction of its proposed distribution system (as described in the record) have been sold and that a contract for the construction of such distribution system has been let and construction begun under the contract.

Paragraph (E) of said order reads as follows:

> South Georgia Natural Gas Company shall be under no obligation to sell and deliver natural gas to either of the cities of Sylvester and Ocilla or to construct additional facilities for the purpose of consummating such sale or sales, unless such city shall, within 12 months from the date of this order, have submitted to this Commission and to South Georgia Natural Gas Company the proof described in paragraph (D) hereof.

Petitioner alleges that it has not as yet started construction of said facilities because of the inability of the cities of Ocilla and Sylvester to comply with the requirements of said order of the Commission. Petitioner states further that it is persuaded that both municipalities have made every reasonable effort to comply with the requirements of said certificate order and that both municipalities will have performed all requirements of said order on or before August 1, 1962.

Petitioner alleges that the City of Ocilla has encountered legal difficulties which have been time-consuming: that in order to correct its voters list, legislation was required to be enacted by the State Legislature. However, the proposed bond issue has now been approved by the voters in Ocilla and Ocilla's application to the Housing and Home Finance Agency for the sale of revenue anticipation bonds at a rate of 3⅝ percent interest was approved by said agency in December 1961.

Petitioner alleges that the engineers and city officials of the City of Ocilla are diligently preparing to receive bids on a construction contract.

Petitioner alleges that the voters in the City of Sylvester have authorized the issuing of $272,000 gas revenue anticipation bonds; that the city has officially sold the bonds to the Housing and Home Finance Agency at an interest rate of 3⅝ percent.[1] An ordinance authorizing the bonds was adopted by the City of Sylvester on January 2, 1962 and proceedings for the judicial validation of said bonds were soon thereafter to be filed. The City of Sylvester has awarded the construction contract in the amount of $218,607.75 and it is alleged that construction is expected to begin during or soon after the month of February 1962.

[1] The interest rate used in hearing and order was 5¼ percent.

Petitioner asserts that it proposes to begin construction now when agricultural land is not under cultivation and thus reduce, and in some cases eliminate, most crop damage.

Petitioner contemplates that construction of its gas system extensions herein authorized will be completed and in operation by August 1, 1962, if the relief requested herein is granted.

The Commission finds:

(1) Good cause has been shown for an extension of time within which to present the proof required by ordering paragraph (D) of the Commission's order herein, but sufficient reason has not been shown for the elimination of the requirement to furnish said proof.

(2) The cities of Ocilla and Sylvester should be granted an extension of time within which to present the proof required by said ordering paragraph (D) until July 1, 1962 and petitioner should be allowed six months from July 1, 1962 within which to complete the facilities necessary to render service to said cities.

The Commission orders:

(A) The petition of South Georgia Natural Gas Company to modify the Commission's order herein effective January 12, 1961 by deleting ordering paragraph (D) thereof be and the same is hereby denied.

(B) The petition of South Georgia Natural Gas Company to modify the Commission's order herein effective January 12, 1962, by amending ordering paragraph (E) so as to extend the time for the completion of the facilities authorized by said order be and the same is hereby granted so that paragraph (E) and (G) will read as follows:

(E) South Georgia Natural Gas Company shall be under no obligation to sell and deliver natural gas to either of the cities of Sylvester and Ocilla or to construct additional facilities for the purpose of cousummating such sale or sales, unless such city shall, on or before July 1, 1962, have submitted to this Commission and to South Georgia Natural Gas Company the proof described in paragraph (D) hereof.

(G) The time within which the facilities hereby authorized for service to Sylvester and Ocilla, Georgia, shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act is hereby fixed at 6 months from the date on which each of the said cities may hereafter submit, to the Commission and to South Georgia Natural Gas Company the evidence described in paragraph (D) hereof, but not later than six months from July 1, 1962.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

WASHINGTON PUBLIC POWER SUPPLY SYSTEM, PROJECT NO. 2244

ORDER AMENDING LICENSE (MAJOR)

(Issued February 28, 1962)

Application was filed on December 22, 1960, and supplemented on August 23 and December 19, 1961, by Washington Public Power Supply System, licensee for major Project No. 2244, for amendment of the license for the proposed project to be located on Lake Creek and Packwood Lake in Lewis County, Wash-

ington, and affecting lands of the United States within the Gifford Pinchot National Forest.

The amendment sought would principally: (1) increase the authorized installed capacity from 26,700 horsepower to 34,800 horsepower; (2) change the location and design of the diversion structure from an earth-fill dam and intake to a concrete drop structure and intake to be located on Lake Creek approximately 400 to 450 feet downstream from the outlet of Packwood Lake; (3) relocate center-lines of certain pipe line sections and add tunnel sections wherever it will improve their hydraulic properties; (4) modify the tailrace canal by minor center-line relocation and detailing of structures; (5) change the design of the powerhouse from a semi-outdoor type to a semi-buried concrete structure; and (6) change the voltage of the 115 kv transmission line, now included in the license, to 69 kv and include in the project works an additional 69 kv transmission line to extend about 50 miles from the project to the Silver Creek Substation of the Bonneville Power Administration.

According to the application and supplements thereto, the proposed changes and additions to the project works are necessary and desirable for the reasons that: (1) as a result of modifications in pipe line gradient to accommodate greater hydraulic capacity, the generating capacity is increased and the increase so realized will enhance the economic feasibility of the project; (2) the redesign and relocation of the spillway crest and the intake structure make a lower head diversion dam feasible; (3) seismic sections studies and pipe line gradient studies made possible better location of the pipe line; (4) relocation of the tailrace serves to benefit the area as a drainage ditch and to return water to the Cowlitz River as requested by the State of Washington Bureau of Fisheries; (5) relocation of the powerhouse was to fit the available foundation conditions and its redesign permitted the accommodation therein of a small horizontal unit; and (6) the construction of the new 69-kv transmission line to the Bonneville Power Adminstration transmission network is required to transmit the additional capacity for use by Member Public Utility Districts.

The principal effects of approval of the amendment sought will be reflected in the description of the project works and the authorized increased installed horsepower capacity of the project with the resultant increase in the administrative annual charges payable under the license as amended.

An Assistant Secretary of the Interior, in reporting on the application, has requested that an additional provision be included in any amended license for the project in the interest of fish life, and that Article 27 of the license be revised by removing therefrom the date specified therein within which the Secretary of the Interior may request modification of project structures in the interest of fish and wildlife resources.

The Director of the Washington Department of Games, in reporting on the application, has requested that an additional provision in the interest of fish life, similar to the provison requested by the Assistant Secretary of the Interior, be included in any amended license for the project.

The Secretary of Agriculture, in reporting on the application, has requested the inclusion in any amended license for the project, additional provisions which the Forest Service believes necessary for the protection of the natural resources of the National forest lands involved, including recreation.

The Commission finds:

(1) Public notice of the filing of the application has been given. No formal protests or petitions to intervene have been received.

(2) The license, amended as hereinafter ordered, will not interfere or be inconsistent with the purposes for which the Gifford Pinchot National Forest was created or acquired, and is in the public interest.

(3) The authorized installed horsepower capacity of the project for the purpose of computing the capacity component of the administrative annual charge is increased to 34,800 horsepower, and the increased annual charge for reimbursing the United States for the costs of administration of Part I of the Federal Power Act, based on such capacity, as hereinafter provided, is reasonable.

(4) The new 69 kv transmission line referred to in item (6) of the second paragraph of this order as extending about 50 miles from the project to the Silver Creek Substation of the Bonneville Power Administration is part of the project within the meaning of Section 3(11) of the Federal Power Act, and should be included in the amended license for the project as hereinafter provided.

(5) The following described revised exhibits filed as part of the application for amendment conform to the Commission's rules and regulations and should be approved as part of the license for the project as hereinafter provided:

Exhibit J: (FPC Nos. 2244–41 and –42);

Exhibit K: (FPC Nos. 2244–43 through –47, –51 and –52, –55 through –64, –72 and –73);

Exhibit L: (FPC Nos. 2244–65, –69 and –70, and –74 through –76); and

Exhibit M: Filed in the Commission December 22, 1960.

(6) The following described exhibits, now part of the license, and which have been superseded by the revised exhibits described in finding (5) above, should be eliminated from the license as hereinafter provided:

Exhibit J: (FPC Nos. 2244–4 and –5);

Exhibit K: (FPC Nos. 2244–6 through –9, –11, and –13 through –34);

Exhibit L: (FPC Nos. 2244–35, –36 and –38); and

Exhibit M: Filed in the Commission April 20, 1959.

The Commission orders:

(A) The exhibits described in finding (5) above as conforming to the Commission's rules and regulations are approved as part of the license for Project No. 2244 and the exhibits described in finding (6) as being superseded are eliminated from the license.

(B) The license for Project No. 2244 is amended, effective as of February 1, 1962, as follows:

PARAGRAPH I. Subparagraphs (a) and (b) of finding (2) of the license are amended to read as follows:

(2) The proposed project will consist of:

(a) All lands constituting the project area and enclosed by the project boundary, or the limits of which are otherwise defined, and/or interest in such lands necessary or appropriate for the purposes of the project, whether such lands or interest therein are owned or held by the Applicant or by the United States; such project area and project boundary being more specifically shown and described by certain exhibits which formed part of the application for license and which are designated and described as follows:

Exhibit J: Sheet 1 (FPC No. 2244–3) Location Map; Sheet 2A (FPC No. 2244–41) General Project Map; Sheet 3A (FPC No. 2244–42) Vicinity Transmission System;

Exhibit K: Sheets, 1A, 4A, 5, 6A, 7 and 8A (FPC Nos. 2244–10, –12 and –43 to –46 incl) Project topography except insofar as a diversion dam is shown on Sheet 8A; Sheet 11A (FPC No. 2244–47) Packwood Lake; Sheets 16A, 19A, and 20A (FPC Nos. 2244–52, –55 and –56) Pipe Line—Plan and Profile; Sheets 21A and 22A (FPC Nos. 2244–57 and –58) Penstock—Plan and Profile; Sheet 23A (FPC No. 2244–59) Penstock, Powerhouse, Yard and Tailrace; Sheet 24A (FPC No. 2244–60) Tailrace Canal; Sheets 25A through 28A (FPC Nos. 2244–61 through –64) Access Road; Sheet 15A (FPC No. 2244–51) Pipeline—Plan

and Profile only insofar as it shows the conduit location; and Sheets 17A and 18A (FPC Nos. 2244–72 and –73) Pipeline—Plan Profile.

(b) Project works consisting of:

A concrete drop structure and intake located on Lake Creek about 450 feet downstream from the outlet of Packwood Lake, providing a maximum operating pool at elevation 2,858.5 feet and creating usable power storage of about 3,500 acre-feet; an excavated approach channel to the intake; a conduit consisting of tunnel and pipeline; a penstock; surge chamber; semi-buried powerhouse containing a 36,700-horsepower turbine connected to a 26,125-kilowatt generator; a tailrace canal; semiautomatic control equipment; a 69-kv transmission line about two miles long extending to existing facilities of Lewis County PUD No. 1 and a 69 kv transmission line extending about 50 miles to the Silver Creek Substation of the Bonneville Power Administration; access roads; and appurtenant electrical and mechanical facilities; the location, nature and character of which are more specifically shown and described by the exhibits hereinbefore cited and by certain other exhibits which also formed part of the application for license or amendment thereof and which are designated and described as follows:

Exhibit L: Sheet 1A (FPC No. 2244–65) Powerhouse Plan and Elevations; Sheet 2B (FPC No. 2244–74) Drop Structure and Intake-General Arrangement; Sheet 3B (FPC No. 2244–75) Intake Area-General Plan, only insofar as it shows Site No. 1; Sheet 4B (FPC No. 2244–76) Drop Structures & Cutoff Details; Sheet 5A (FPC No. 244–69) Pipeline and Penstock, Sections and Details; Sheet 6A (FPC No. 2244–70) Tailrace Canal Structures, Plans and Sections; Sheet 3 (FPC No. 2244–37) Geological Plan and Sections—Intake Area; Sheet 5 (FPC No. 2244–39) Powerhouse Yard and Tailrace, Plans and Sections, only insofar as it shows the tailrace canal sections; and

Exhibit M: General Description and General Specifications of Equipment, filed in the Commission December 22, 1960.

PARAGRAPH II: Article 27 of the license is amended to read as follows:

Article 27. The Licensee shall construct, maintain and operate such protective devices and shall comply with such reasonable modifications of the project structures and operation in the interest of fish and wildlife resources, provided that such modifications shall be reasonably consistent with the primary purpose of the project, as may be prescribed hereafter by the Commission upon its own motion or upon recommendation of the Secretary of the Interior or the Washington Departments of Fisheries and Game or the Forest Service, after notice and opportunity for hearing and upon a finding that such modifications are necessary and desirable and consistent with the provisions of the Act: Provided further, That subsequent to approval of the final design drawings prior to commencement of construction no modifications of project structures in the interest of fish and wildlife resources which involve a change in the location, height or main structure of a dam, or the addition of or changes in outlets at or through a dam, or a major change in generating units, or a rearrangement or relocation of a powerhouse, or major changes in a spillway structure shall be required.

PARAGRAPH III. Subparagraph (i) of Article 31 of the license is amended to read as follows:

(i) For the purpose of reimbursing the United States for the costs of administration of the Federal Power Act, a reasonable annual charge in accordance with the provisions of Part 11 of the Commission's regulations. The authorized installed capacity for such purpose is 34,800 horsepower;

PARAGRAPH IV. Article 35 of the license is amended to read as follows:

Article 35. The Licensee shall, within one year following the date of completion of the project, submit for Commission approval Exhibits F and K show-

ing the project area and boundary of the project and Exhibits F and K for the transmission lines, all prepared in accordance with the Commission's rules and regulations.

PARAGRAPH V. The license is amended by adding thereto the following articles:

Article 36. Prior to the start of construction of any phase of the project occupying national forest land between the surge chamber and Packwood Lake, the Licensee shall submit to the authorized representatives of the Commission and the Forest Service construction plans, procedures, and methods pertaining to control against land sliding and prevention of silt and debris deposition in Packwood Lake and Lake Creek as a result of construction, operation, and subsequent maintenance of project facilities. No construction between the surge chamber and Packwood Lake, including pipeline, pipeline access and drop structures and inlet channel, is to start until the construction details have been approved by the authorized representatives.

Article 37. The Licensee shall operate the project so that the maximum operating pool shall be at elevation 2858.5 and the minimum operating pool shall be elevation 2850.5. During the period each year between May 1 and September 15, the Licensee shall maintain the pool level at elevation 2857, except for conditions which may occur which are beyond the control of the Licensee.

Article 38. The Licensee shall, prior to commencing construction of the project access road, submit to and obtain Commission approval of revised Exhibit K maps showing the location of the access road.

Article 39. The Licensee shall participate with the United States Forest Service in a five-year recreation and fishery water flow study to determine the long term minimum flow requirements needed for multiple-use purpose of the National Forest, such study to begin with the completion of construction of the drop structure. The Licensee shall initially maintain a minimum flow of 10 cfs immediately below the drop structure and may adjust the flows between 5 and 15 cfs during the study period as directed by the authorized representative of the Commission upon the advice of the Forest Service: *Provided, however,* That the minimum water flow in Lake Creek below the Primary State Highway No. 5 bridge crossing of Lake Creek shall not be less than 10 cfs. Within six months after completion of the study, the Forest Service may recommend to the Commission minimum flows in Lake Creek immediately below the drop structure for multiple-use purposes of the National Forest. The Licensee shall comply with such reasonable modification of the minimum flow requirements prescribed herein as the Commission may prescribe hereafter upon its own motion or upon recommendation of the Forest Service, after notice and opportunity for hearing.

(C) This amendment in the manner set out above shall not operate to alter or amend the license in any other respect, and shall not in any way constitute a waiver of any other part, provision or condition of the license.

(D) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313(a) of the Federal Power Act and failure to file such an application shall constitute acceptance of this amendment of license. In acknowledgment of the acceptance of this amendment of license, it shall be signed for the Licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

KANSAS-NEBRASKA NATURAL GAS COMPANY, INC., DOCKET NOS. CP60-84 AND CP62-7

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 1, 1962)

On April 22, 1960, as supplemented on May 20, 1960, Kansas-Nebraska Natural Gas Company, Inc. (Applicant) filed in Docket No. CP60-84 an application pursuant to Section 7 of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of transmission facilities extending from Alliance, Nebraska, to the communities of Chadron, Crawford, Gordon, Hay Springs, Hemingford and Rushville, all in Nebraska, and authorizing the sale and delivery of natural gas to Western Gas Fuel Company (Western) for resale and distribution in said communities.

Specifically, Applicant proposes to construct and operate the following facilities: approximately 17 miles of 8-inch pipeline south of Alliance replacing an equal amount of 6-inch pipeline which will be salvaged; about 126 miles of 2- to 6-inch lines from Alliance to the six towns;[1] and approximately 24 miles of 8-inch pipeline extending from an existing 10-inch line in the vicinity of Sidney, Nebraska, to Applicant's existing 11 miles of 10-inch line leased to North Central Gas Company (North Central) south of Northport, Nebraska.

Applicant states that gas is presently brought to the Alliance area from the Sidney area through partially looped lines extending from Sidney to Northport. One of these parallel lines is owned and operated by North Central and the other is the aforementioned 10-inch line owned by Applicant and leased to North Central. North Central presently transports gas for Applicant through this leased line. Originally Applicant sought herein to abandon the transportation agreement and to assume operation of the leased line itself. However, by its amendment to its application in Docket No. CP60-84, filed September 7, 1961, Applicant requests deletion of requested authorization to construct and operate the 24 miles of 8-inch line to have been constructed from the vicinity of Sidney to Applicant's line leased to North Central. The amendment shows that North Central will continue the transportation service for Applicant and that Applicant will install three 125-horsepower compressor units at Northport rather than the originally proposed 24 miles of 8-inch line to have been constructed between Sidney and Northport.

The following are the estimated natural gas requirements of Western for the areas proposed to be served:

	Volumes—Mcf at 14.73 psia		
	1st year	2d year	3d year
ANNUAL			
Total firm requirements	94,700	355,400	533,000
Total interruptible industrial requirements[2]	14,000	38,000	38,000
Total	108,700	393,400	571,000
PEAK DAY			
Total firm requirements	2,200	3,960	4,445

[1] Applicant will also build town border stations for the six communities.

[2] The industrial gas would be used at Nebraska State College for boiler fuel.

On July 14, 1961, as supplemented on August 2, 1961, Applicant filed in Docket No. CP62–7 an application pursuant to Section 7 of the Natural Gas Act for a certificate of public convenience and necessity authorizing Applicant to remove three 125-horsepower compressor units from its Holdrege compressor station and to relocate said units at a new station at Northport.

As set forth above, Applicant in Docket No. CP60–84 proposes, among other things, to construct and operate 24 miles of 8-inch pipeline between Sidney and Northport to help serve six new communities north of Alliance. Applicant states that the 1960–1961 peak demand of Alliance and the six new communities was met without the construction of the 8-inch line, and, therefore, Applicant has decided to postpone installation of said line.[2]

Applicant states that it is currently completing contracts for purchase of new gas supplies in Wyoming which will probably require a change in its present operations between Sidney and Northport. Applicant further states that this contemplated change might enable it to provide service to the Alliance-Chadron area more economically than previously contemplated, and, therefore, rather than construct the subject Sidney-Northport 8-inch line, which may not be properly sized to handle the future Wyoming gas, Applicant proposes to relocate the three 125-horsepower units from Holdrege to Northport in order to meet the future increased requirements of the Alliance-Chadron area. The three units have only operated 22 hours in the last 5½ years at Holdrege.

The total estimated cost of constructing the proposed facilities in Docket No. CP60–84 is $1,347,200, which estimate does not include the cost of constructing the postponed 8-inch Sidney-Northport line. The estimated net cost of relocating the facilities in Docket No. CP62–7 is $48,000. Applicant will finance the estimated costs in both dockets from current working capital.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 21, 1962, respecting the matters involved in the issues presented by the applications, as supplemented and amended, herein. No petition to intervene or protest to the granting of the applications has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Kansas-Nebraska Natural Gas Company, Inc., a Kansas corporation having its principal place of business in Phillipsburg, Phillips County, Kansas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G–259 (3 FPC 966).

(2) The facilities hereinbefore described, as more fully described in the applications, as supplemented and amended, in these proceedings, are to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission and the construction, operation and relocation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

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[2] Applicant was granted temporary authorization by letter, dated July 8, 1960, to construct and operate facilities and to sell natural gas as proposed in Docket No. CP60–84. Applicant was granted temporary authorization by letter, dated October 6, 1961, in Docket No. CP62–7.

(4) The construction, operation and relocation of the proposed facilities by Applicant are required by the public convenience and necessity and certificates therefor should be issued as herinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificates issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (c)(4) and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Certificates of public convenience and necessity be and the same are hereby issued authorizing Applicant, Kansas-Nebraska Natural Gas Company, Inc., in Docket No. CP60-84, to construct and operate the proposed facilities and to sell and deliver natural gas to Western Gas Fuel Company for resale, and in Docket No. CP62-7, to relocate facilities, all as hereinbefore described and all as more fully described in the applications, filed in the respective dockets, as supplemented and amended, herein, upon the terms and conditions of this order.

(B) The certificates issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (c)(4) and (e) of Section 157.20 of such Regulations.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

KENTUCKY GAS TRANSMISSION CORPORATION AND THE UNION LIGHT, HEAT AND POWER COMPANY, DOCKET NO. CP61-312

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND PERMITTING AND APPROVING ABANDONMENT

(Issued March 1, 1962)

On June 7, 1961, as supplemented on September 21, 1961, Kentucky Gas Transmission Corporation (Kentucky Gas), 1700 MacCorkle Avenue, S.E., Charleston, West Virginia, and The Union Light, Heat and Power Company (Union), 7th & Scott Streets, Covington, Kentucky, (sometimes hereinafter referred to jointly as Applicants) filed a joint application pursuant to Section 7 of the Natural Gas Act for: (a) permission and approval for Kentucky Gas to abandon by sale to Union and The Cincinnati Gas & Electric Company (Cincinnati) a segment of Kentucky Gas' 24-inch transmission pipeline AM-7 located in Kentucky and Ohio, including a multiple 20-inch O.D. crossing of the Ohio River; and (b) a certificate of public convenience and necessity authorizing Union to acquire and operate that portion of the subject 24-inch pipeline and subject river crossing located in Kentucky and authorizing Union to transport and deliver for the account of Kentucky Gas, through the facilities to be acquired, volumes of natural gas deliverable to Cincinnati by Kentucky Gas.

The facilities to be sold by Kentucky Gas to Union and Cincinnati are:

	Original cost	Depreciated cost as of Dec. 31, 1960
To Union: 25,349 feet of 24-inch gas pipeline AM-7 including 4,915 feet of 20-inch river crossing and related facilities extending from Erlanger, Ky., to the Kentucky-Ohio State line	$683,169.93	$623,736.77
To Cincinnati: 1,572 feet of 20-inch river crossing and related facilities extending from the Kentucky-Ohio State line to an existing point of connection with Cincinnati near Anderson Ferry, Ohio	93,171.25	84,547.81

Applicants state that the proposed transfer of facilities is designed to eliminate the necessity of constructing duplicate pipeline facilities for the distribution of peak-shaving propane-air gas following the development by Union of propane storage facilities in the Commonwealth of Kentucky.

Union and Cincinnati have agreed to purchase the subject facilities at a price which would be the original cost less accrued depreciation as of the date of closing.

The proposed transportation service by Union is for the purpose of maintaining existing service rendered by Kentucky Gas to Cincinnati through the facilities herein proposed to be acquired. Union will charge Kentucky Gas $97,895 for the transportation and delivery of gas to Cincinnati based on a cost formula including 6¾ percent return and associated income taxes. Kentucky Gas, in turn, will collect the same amount from Cincinnati. Union is presently making other deliveries to Cincinnati for the account of Kentucky Gas wherein a rate of return of 6¼ percent is used in the computation of charges. It appears to the Commission that Union has shown no justification in the subject proceeding for the use of a 6¾ percent rate of return; therefore, the authorization hereinafter granted to Union shall limit the rate of return to 6¼ percent until another rate is permitted by the Commission. Union consented to this condition in its letter filed September 21, 1961.

Union was granted temporary authorization by letter, dated November 29, 1961, to acquire and operate the subject facilities.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 19, 1962, respecting the matters involved in and the issues presented by the joint application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Kentucky Gas Transmission Corporation, a Delaware corporation having its principal place of business in Charleston, West Virginia, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order issued October 6, 1958, in Docket No. G–15288 (20 FPC 463).

(2) Applicant, The Union Light, Heat and Power Company, a Kentucky corporation having its principal place of business in Covington, Kentucky, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of November 14, 1955, in Docket No. G–8610 (14 FPC 1097).

(3) The facilities proposed to be acquired and operated by Union as hereinbefore described and as more fully described in the joint application, as supplemented, in this proceeding, will be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the acquisition and operation thereof by Applicant are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The transportation of natural gas by Union for the account of Kentucky Gas, as more fully described in the application, as supplemented, in this proceeding, will be made in interstate commerce, subject to the jurisdiction of the Commission, and such transportation is subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) The acquisition and operation of the facilities and the transportation of natural gas therefrom as proposed by Union, are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(6) The facilities to be abandoned by sale by Kentucky Gas, as hereinbefore described and as more fully described in the joint application herein are subject to the jurisdiction of the Commission and abandonment of such facilities by Kentucky Gas is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(7) Such abandonment by Kentucky Gas, as hereinbefore described, is permitted by the public convenience and necessity, and an order authorizing and approving same should be issued as hereinafter ordered.

(8) Kentucky Gas and Union are able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(9) Public convenience and necessity require that the certificate issued hereinafter to Union and the rights granted thereunder be conditioned upon Union's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (d) and (e) of Section 157.20 of such Regulations.

(10) The certificate hereinafter issued to Union should be conditioned to revise Union's transportation charges proposed in the subject application to include a 6¼ percent rate of return and associated income taxes, in lieu of the proposed 6¾ percent rate of return and associated income taxes, until another rate of return is permitted by the Commission.

(11) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing The Union Light, Heat and Power Company to acquire and operate the facilities and to transport natural gas for the account of Kentucky Gas as hereinbefore described, all as more fully described in the joint application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Union's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (d) and (e) of Section 157.20 of such Regulations.

(C) The certificate issued to Union in paragraph (A) above is hereby conditioned to revise Union's transportation charges proposed in the subject application to include a 6¼ percent rate of return and associated income taxes, in lieu of the proposed 6¾ percent rate of return and associated income taxes, until another rate of return is permitted by the Commission.

(D) The acquisition hereinabove authorized shall be consummated and operation begun by Union within 6 months of the date hereof.

(E) Permission for and approval of the abandonment by sale by Kentucky Gas Transmission Corporation of the facilities hereinbefore described, all as more fully described in the joint application in this proceeding, be and the same is hereby granted.

(F) Kentucky Gas shall advise the Commission of the date of the abandonment by sale of the facilities within 10 days of the date thereof.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

MIDWESTERN GAS TRANSMISSION COMPANY, DOCKET NOS. G–16841, RP61–19 AND CP61–38

ORDER AMENDING ORDER ISSUED JANUARY 23, 1962

(Issued March 1, 1962)

It appears that the order of the Commission issued on January 23, 1962, 27 FPC 171, amending certain orders in the above-entitled dockets contained an inadvertent inaccuracy which should be corrected as hereinafter ordered.

The Commission finds:

Ordering paragraph (C) of the Commission's order issued on January 23, 1962, in Docket Nos. G–16841, RP61–19 and CP61–38 should be amended as hereinafter ordered.

The Commission orders:

(A) Ordering paragraph (C) of the Commission's order issued on January 23, 1962, in Docket Nos. G–16841, RP61–19 and CP61–38 is hereby amended to read as follows:

(C) The order of the Commission issued July 27, 1961, in Docket No. CP61–38 be and the same is hereby amended by deleting therefrom the fourth paragraph of the preliminary statement, and by adding a new ordering paragraph (G) to read as follows:

(G) The deliveries of natural gas for the testing and development of storage and for service to the aforesaid communities are to be made from Northern Illinois' existing authorized contract quantity from Midwestern. These deliveries are to be made pursuant to Midwestern's FPC Gas Rate Schedule CD–1 and the related gas service agreement between Midwestern and Northern Illinois dated July 20, 1961.

(B) In all other respects, said order issued on January 23, 1962, in Docket Nos. G–16841, RP61–19 and CP61–38 shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

MURPHY CORPORATION, ET AL., DOCKET NO. RI61-145; MURPHY CORPORATION, DOCKET NO. RI61-146

ORDER DENYING MOTION TO TERMINATE PROCEEDINGS

(Issued March 1, 1962)

On August 28, 1961, Murphy Corporation, *et al.*, and Murphy Corporation (Murphy), filed a motion to terminate the above-designated proceedings, involving proposed increased rates which have been suspended.

In support of its motion, Murphy cites the Commission order of February 27, 1961, in Murphy Corporation, *et al.*, Dockets Nos. G-9548, *et al.*, 25 FPC 334, terminating proceedings under Sections 4(e) and 5(a) of the Natural Gas Act. Murphy contends that the costs which it presented in the terminated proceedings justify the granting of the motion now under consideration.

In the aforementioned order terminating the proceedings in Docket Nos. G-9548, *et al.*, we stated that in a case such as that then before us, in which the increased rate was filed, the hearing held, and the examiner's decision issued prior to the release of the Statement of General Policy No. 61-1, on September 28, 1960, 24 FPC 818, the purposes of the Natural Gas Act would best be served by the expeditious disposition of the proceedings on the existing record, to the extent that the record affords a reasonable basis for a determination of the lawfulness of the proposed rates.

The proceedings in Docket Nos. G-9548, *et al.*, related to the Section 4(e) proceedings consolidated therewith, and to Murphy's rates as of the time of the order. The findings in that order in no manner passed upon the justness and reasonableness of any suspended rates not consolidated therewith. In the instant proceedings, not consolidated with those in Docket Nos. G-9548, *et al.*, the proposed increased rates exceed the applicable area price ceiling established by the Statement of General Policy No. 61-1. In the above-cited order of February 27, 1961, we stated that it was our intention to consider such proposed increases over the indicated rate level in general area-wide hearings, to determine just and reasonable rates on an area basis.

The Commission finds:

For the reasons hereinabove stated, Murphy's motion to terminate the proceedings in Docket Nos. RI61-145 and RI61-146 should be denied.

The Commission orders:

Murphy's motion to terminate the proceedings in Docket Nos. RI61-145 and RI61-146 is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NATURAL GAS STORAGE COMPANY OF ILLINOIS, DOCKET NO. CP62-136

FINDINGS AND ORDER PERMITTING AND APPROVING ABANDONMENT OF SERVICE

(Issued March 1, 1962)

On November 30, 1961, Natural Gas Storage Company of Illinois (Applicant) filed in Docket No. CP62-136 an application for permission and approval to

abandon natural gas storage service for three of its existing customers, all as more fully set forth in the application.

The authorized maximum daily storage-withdrawal service for said customers is as follows:

Customers:	Mcf
Citizens Gas Company	473
City of Nashville, Illinois	656
United Cities Gas Company	778
Total	1,907

The three customers are also customers of Natural Gas Pipeline Company of America (Natural) which sells gas to them for resale. Under the storage arrangement, the customers would advise Natural to deliver during the off-peak periods portions of their contract demand gas to Applicant for injection into storage. During winter periods the customers would request Applicant to withdraw their gas for return to them in volumes up to the maximum daily quantities authorized.

In recent expansion applications (Docket Nos. CP61–30 and CP61–185), Natural was authorized to sell additional contract demand gas to the three customers involved herein. As indicated in the CP61–30 proceedings, the customers have determined that, with the increased contract demands from Natural, they no longer need the storage service rendered for them by Applicant. Accordingly, Applicant proposes to abandon such storage service.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 21, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Natural Gas Storage Company of Illinois, an Illinois corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order issued September 11, 1952, in Docket No. G–1757 (11 FPC 366).

(2) The service to be abandoned, as hereinbefore described, and as more fully described in the application in this proceeding, is subject to the jurisdiction of the Commission, and abandonment of such service is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(3) Such abandonment by Applicant, as hereinbefore described, is permitted by the public convenience and necessity, and an order approving same should be issued as hereinafter ordered.

(4) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

Permission for and approval of the abandonment by Natural Gas Storage Company of Illinois of the service hereinbefore described, all as more fully described in the application in this proceeding, be and the same is hereby granted.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

THE OHIO FUEL GAS COMPANY, DOCKET NO. CP62-138

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 1, 1962)

On December 1, 1961, The Ohio Fuel Gas Company (Applicant) filed in Docket No. CP62-138 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of miscellaneous pipeline replacement and loop facilities during the calendar year 1962 at a total cost not to exceed $2,000,000, with no single project to exceed cost of $500,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to allow Applicant to act with reasonable dispatch in scheduling and undertaking construction of minor facilities at various locations on its transmission system. The subject application is not for authorization for any individual facility for the specific purpose of extending service to a new market areas, communities, mail-line industrial customers, or for underground storage.

The proposed facilities will be financed by the Columbia Gas System, Inc., Applicant's parent.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 21, 1962, respecting the matters involved in and the issues presented by the application in this proceeding. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, The Ohio Fuel Gas Company, an Ohio corporation having its principal place of business in Columbus, Ohio, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order issued August 21, 1945, in Docket No. G-871 (4 FPC 1033).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing pipeline system, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to transport and sell natural gas during the calendar year 1962 as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

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(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before March 1, 1963, a statement under oath showing by projects: (a) the location of said project or projects, (b) a description of said project or projects, (c) facilities replaced, if any, (d) abandonment of service, if any, (e) market areas involved, (f) capacity increase, if any, and (g) the actual cost of the facilities constructed under the authorization hereinafter granted.

(6) The authorization hereinafter granted should be limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed thereunder should be limited to $2,000,000, with no single project to exceed a cost of $500,000.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(8) The certificate issued hereinafter should be conditioned upon the Applicant's obtaining permission and approval, as required, from the Federal Power Commission or the Ohio Public Utilities Commission for any abandonment of service which may result from the replacement of facilities authorized by said certificate.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing The Ohio Fuel Gas Company to construct and operate during the calendar year 1962 the facilities hereinbefore described, as more fully described in the application in this proceeding.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) The certificate issued by paragraph (A) above and the rights granted thereunder is further conditioned upon Applicant's obtaining permission and approval, as required, from the Federal Power Commission or the Ohio Public Utilities Commission for any abandonment of service which may result from the replacement of facilities authorized by said certificate.

(D) Applicant shall submit, on or before March 1, 1963, a statement under oath showing by projects: (a) the location of said project or projects, (b) a description of said project or projects, (c) facilities replaced, if any, (d) abandonment of service, if any, (e) market areas involved, (f) capacity increase, if any, and (g) the actual final cost of the facilities constructed under the authorization hereinbefore granted.

(E) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for

facilities to be constructed thereunder are hereby limited to $2,000,000, with no single project to exceed a cost of $500,000.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TEXAS EASTERN PENN JERSEY TRANSMISSION CORPORATION, DOCKET NO. G–2341; WILCOX TREND GATHERING SYSTEM, INC., DOCKET NO. G–13007

ORDER TERMINATING PROCEEDINGS

(Issued March 2, 1962)

On May 10, 1957, Texas Eastern Penn Jersey Transmission Corporation (Penn Jersey) and Wilcox Trend Gathering System, Inc. (Wilcox Trend) tendered for filing proposed changes in rate for sales of natural gas to Texas Eastern Transmission Corporation (Texas Eastern). The filings of both Penn Jersey and Wilcox Trend were premised on Texas Eastern's tender of an increase in rate, which reflected, *inter alia*, a 6¾% rate of return, and was suspended by order of the Commission issued June 7, 1957, in Docket No. G–12706. The filings of Penn Jersey and Wilcox Trend, which similarly proposed to reflect a 6¾% rate of return, were suspended in Docket Nos. G–2341 and G–13007, respectively, until November 10, 1957, to coincide with the suspension period ordered with respect to Texas Eastern's proposed rate increase in Docket No. G–12706. No hearings have been held in Docket Nos. G–2341 or G–13007.

At the time of their filings, both Wilcox Trend and Penn Jersey were subsidiaries of Texas Eastern; however, on January 1, 1959, Texas Eastern acquired the facilities of these two subsidiaries by merger.[1] Thereafter, Texas Eastern filed an additional increase, which was suspended in Docket No. G–18841 and subsequently allowed to become effective December 1, 1959. On January 25, 1961, in Docket Nos. G–12706 and G–18841, 25FPC 172, the Commission approved an offer of settlement with the rates of return for both proceedings computed as if Texas Eastern, Penn Jersey and Wilcox Trend constituted a single company for the period of the test year involved. Inasmuch as the refunds ordered in Docket Nos. G–12706 and G–18841 are based upon the rates of the merged companies as a single corporate entity, the refund obligations in Docket Nos. G–2341 and G–13007 on a separate basis are no longer applicable.

The Commission finds:

In view of the merger of the respondents in the above-designated proceedings with Texas Eastern, and the determination of Texas Eastern's rates by a settlement dispositive of the issues involved therein, good cause exists for allowing the termination as moot of the proceedings in Docket Nos. G–2341 and G–13007.

The Commission orders:

The proceedings in Docket Nos. G–2341 and G–13007 are hereby terminated.

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[1] The merger of Penn Jersey and Texas Eastern Transmission Corporation was approved by order of the Commission issued July 9, 1958, and by order issued on the same date in Docket No. G–14870, Wilcox Trend was permitted to abandon its facilities and Texas Eastern was authorized to acquire and operate such facilities. [20 FPC 21.]

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

IDAHO POWER COMPANY, PROJECT NO. 2055

ORDER DETERMINING ACTUAL LEGITIMATE ORIGINAL PROJECT COST; NET CHANGE THEREIN; AND PRESCRIBING ACCOUNTING THEREFOR

(Issued March 2, 1962)

Idaho Power Company, Licensee for Project No. 2055,[1] on November 9, 1954, filed its initial statement, pursuant to Section 4.1 of the Commission's Regulations under the Federal Power Act, claiming for Project No. 2055, as of October 31, 1954, an actual legitimate original cost of $19,757,269.72.[2] In addition, Licensee's books and records show for the period November 1, 1954, through December 31, 1958, a net increase in project cost of $90,593.38, resulting in a total claimed or recorded actual legitimate original cost of the project as of December 31, 1958, of $19,847,863.10. The recorded net increase of $90,593.38 in the cost of the project for the period November 1, 1954, through December 31, 1958, results from recorded project gross additions of $95,863.23, project gross retirements of $382.50, and credit adjustments of $4,887.35, all as more specifically shown in the attached Schedule II.

The Commission's staff made a field examination of the books and records of Licensee and other data for the purpose of ascertaining the correctness of the claimed project cost as of October 31, 1954, and the correctness of recorded project cost changes and resulting project cost as of December 31, 1958.

Following that examination, an agreement, subject to Commission approval was reached between the staff and Licensee's representatives with respect to certain proposed adjustments involving (1) the reclassification and transfer of certain items among the project plant accounts and the elimination of $54,760.52 from the claimed and recorded project cost as of October 31, 1954; (2) a debit adjustment of $11.19, representing the difference between project cost as recorded on Licensee's books of account as of October 31, 1954, and Licensee's claimed project cost as shown in FPC Form No. 6 as of that date; and (3) the accounting dispositions of the foregoing amounts.

Based upon the proposed adjustments, the resulting revised actual legitimate original cost of Project No. 2055 as of October 31, 1954 is $19,702,509.20; the resulting revised net increase or change in the project cost is $90,593.38, consisting of gross additions of $95,863.23, gross retirements of $382.50, and credit adjustments of $4,887.35; and the resulting revised actual legitimate original cost of the project as of December 31, 1958, is $19,793,102.58.

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[1] The project is located on the Snake River in Elmore, Owyhee, Ada, and Canyon Counties, Idaho, and may be described as the C. J. Strike hydroelectric development. The license, issued pursuant to Section 4(e) of the Federal Power Act, authorizing the construction, operation and maintenance of the project, is by its terms effective for a period of 50 years, commencing December 1, 1950.

[2] Article 23 of the license provides for Commission determination of the actual legitimate original cost of the project and of any additions thereto or betterments thereof.

The proposed eliminations relative to project costs in the total amount of $54,760.52 as of October 31, 1954, are composed of the following items:

Nonproject preliminary investigation costs	($31,644.81)
FPC annual charges applicable to operations	(163.20)
Interest accrued after commercial operations	(19,848.74)
Delayed credits applicable to construction recorded after October 31, 1954	(2,225.39)
Taxes applicable to period after date of commercial operations	(878.38)
Total	(54,760.52)

The proposed accounting disposition of the amounts involved in the adjustments proposed above to bring Licensee's claimed and recorded project cost as of October 31, 1954, into agreement with the recommended project cost tentatively agreed to between Licensee and the staff are shown by the following composite journal entry:

Account No.[1]		Debit	Credit
107	Construction work in progress	$2,225.39	
183	Preliminary survey and investigation charges	31,644.81	
216	Unappropriated earned surplus	20,890.32	
101	Electric plant in service—Project No. 2055		$54,760.52

[1] Account references are to account numbers and titles prescribed in the Commission's revised Uniform System of Accounts for Public Utilities and Licensees, effective Jan. 1, 1961.

In its examination of Licensee's books of account for the period November 1, 1954, through December 31, 1958, the Commission's staff found that the total project cost as recorded on Licensee's books of account as of December 31, 1958, was $19,793,091.39, or $11.19 less than the total project cost as of that date as recommended by the staff. The amount of $11.19 represents the difference between the total project cost as of October 31, 1954, as recorded upon Licensee's books of account, and the total claimed project cost shown in FPC Form No. 6 as of that date, which difference was still found to exist on Licensee's books of account as of December 31, 1958.

The proposed accounting disposition of the amount involved in the proposed adjustment to bring Licensee's recorded project cost and changes into agreement with the recommended project cost and changes as of December 31, 1958, tentatively agreed to between Licensee and the staff is shown by the following journal entry:

Account No.		Debit	Credit
101	Electric plant in service—Project No. 2055	$11.19	
401	Operation expense		$11.19

After giving effect to the above proposed adjustments, the Commission's staff recommends and Licensee, by its revised statement of project original cost filed on September 17, 1956, confirming its agreement to the proposed adjust-

ments, accounting disposition and resulting project costs for Project No. 2055 (C. J. Strike), concurs that the Commission determine (1) the actual legitimate original cost of the C. J. Strike project as of October 31, 1954, to be $19,702,509.20; (2) the net increase or change in the actual legitimate original cost of the C. J. Strike project during the period from November 1, 1954, through December 31, 1958, to be $90,593.38, consisting of project gross additions of $95,863.23, project gross retirements of $382.50, and credit adjustments of $4,887.35; and (3) the actual legitimate original cost of the C. J. Strike project at December 31, 1958, to be $19,793,102.58, classified by primary plant accounts of the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees as shown in the attached Schedules I and II.

The Idaho Public Utilities Commission was advised by letter of this Commission of the proposed adjustments, including the accounting disposition and resulting project costs and changes therein, all as recommended by the Commission's staff and agreed to by the Licensee as set forth above. By its letters dated September 14, 1956, and August 22, 1961, that Commission indicated that it had no objection to the foregoing.

The Commission finds:

(1) Licensee, by its tentative agreement and its revised statement of project claimed cost filed on September 17, 1956 showing the proposed adjustments and accounting disposition thereof and the resulting project costs, and the Idaho Public Utilities Commission, by its letters dated September 14, 1956 and August 22, 1961, have obviated the necessity for notice and opportunity to protest provided in Sections 4.4 and 4.5 of the Commission's Regulations under the Federal Power Act.

(2) It is necessary and appropriate for the purposes of the Federal Power Act that the charges of Ebasco Services Incorporated includable as a part of the actual legitimate original cost of Project No. 2055 as of December 31, 1958, be tentatively approved by the Commission, subject to future revision so as to reflect any portion thereof that may be determined later to represent non-allowable intercompany profits.

(3) The foregoing adjustments, including the accounting dispositions, are reasonable and appropriate for the purposes of the Federal Power Act, and therefore, should be approved and directed as hereinafter provided.

(4) The actual legitimate original cost of Project No. 2055 as of October 31, 1954, is $19,702,509.20; the net increase of change in the actual legitimate original cost of Project No. 2055 from November 1, 1954, through December 31, 1958, is $90,593.38, comprised of gross additions of $95,863.23, gross retirements of $382.50, and credit adjustments of $4,887.35; and the resulting actual legitimate original cost of the project as of December 31, 1958, is $19,793,102.58, all classified by primary plant accounts as shown by the attached Schedules I and II.

The Commission orders:

(A) The provisions of Sections 4.4 and 4.5 of the Commission's Regulations under the Federal Power Act are hereby waived for the purposes of this order.

(B) The foregoing adjustments and accounting dispositions, as proposed by the staff and agreed to by the Licensee, are hereby approved and directed to be made by the Licensee.

(C) Licensee, to the extent that it has not already done so, shall establish and maintain control and detailed plant accounts for Project No. 2055, showing the debit balance of $19,702,590.20 as of October 31, 1954; the debit amount of $90,593.38 as the net increase or change in the project cost for the period November 1, 1954, through December 31, 1958; and the total debit balance of $19,793,102.58, as the actual legitimate original cost of the project as of December, 31, 1958, all as more specifically shown in the attached Schedules I and II classified by primary plant accounts of the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees.

(D) Licensee shall within 90 days from the issuance of this order file with the Commission FPC Form No. 7 and three certified copies of its adjusting journal entries showing compliance with this order.

Project No. 2055—Idaho
(C.J. Strike)

Schedule No. I

Actual legitimate original cost as of Oct. 31, 1954

Account (A)	Claimed cost	Contractor's ind. & O.H. costs as distributed by licensee	Transfers between account		Reclassified claimed cost	Adjustments		Allowed cost	
			Account	Amount		Number	Amount	Before distribution of ind. & O.H.	After distribution of ind. & O.H.
Production plant:									
320 Land and land rights	$1,761,918.84	($24,392.83)	To 61	($106,260.72)	$1,631,265.29	4 4	$67.30 (55.00)	$1,631,277.59	$1,707,968.53
321 Structures and improvements	1,772,198.83	(349,744.78)	From 324	4,369.88	1,426,823.93			1,426,823.93	1,999,644.05
322 Reservoirs, dams, and waterways.	8,613,373.41	(1,924,896.55)			6,688,476.86	4	(1,897.57)	6,686,579.29	9,692,778.18
323 Water wheels, turbines and generators.	3,216,364.91	(90,904.32)			3,125,460.59			3,125,460.59	3,630,228.67
324 Accessory electric equipment	245,826.05	(6,359.33)	To 321	(4,369.88)	235,096.84			235,096.84	271,774.68
325 Miscellaneous power plant equipment.	197,507.00	(7,980.36)			189,526.64			189,526.64	222,307.02
326 Roads, railroads, and bridges		(37,246.81)	From 61	166,169.07	128,922.26			128,922.26	187,034.14
	15,807,189.04	(2,441,524.98)		59,908.35	13,425,572.41		(1,885.27)	13,423,687.14	17,701,735.27
Transmission plant:									
340 Land and land rights	42,195.95		To 71	(15,722.56)	26,473.39			26,473.39	27,356.55
341 Clearing land and rights-of-way	2,349.31				2,349.31			2,349.31	2,757.52
342 Structures and improvements	78,179.27	(11,733.80)			66,445.47			66,445.47	87,995.88
343 Station equipment	478,090.48	(6,591.48)			471,499.00			471,499.00	538,122.04
344 Steel towers and fixtures	98,647.28				98,647.28			98,647.28	115,787.99
345 Poles and fixtures	428,172.99				428,172.99			428,172.99	502,571.30
346 Overhead conductors and devices.	617,486.60				617,486.60			617,486.60	724,779.59
349 Roads and trails	1,195.35				1,195.35			1,195.35	1,403.06
	1,746,317.23	(18,325.28)		(15,722.56)	1,712,269.39			1,712,269.39	2,000,773.93
	17,553,506.27	(2,459,850.26)		44,185.79	15,137,841.80		(1,885.27)	15,135,956.53	19,702,509.20

Indirect costs:									
61 Temporary construction facilities.	265,109.80	331,720.38	From 320	106,260.72	536,921.83	4	(340.12)	536,581.71	
			To 426	(166,169.07)					
62 Construction equipment	19,776.51	848,300.44			868,076.95			868,076.95	
63 Camp and commissary	7,097.20	111,989.38			119,086.58			119,086.58	
64 Labor expense		23,237.02			23,237.02			23,237.02	
65 Superintendence, timekeepers, clerks, etc.	20,862.49	310,984.05			331,846.54			331,846.54	
66 Insurance, injuries, and damages.	2,339.62	1,658.83			3,998.45			3,998.45	
67 Power used in aid of construction.	41,652.16				41,652.16			41,652.16	
69 Contractor's fee		572,568.15			572,568.15			572,568.15	
	356,837.78	2,200,458.25		(59,908.35)	2,497,387.68		(340.12)	2,497,047.56	
Overhead costs:									
71 Engineering	1,068,141.26	(3,408.99)	From 340	15,722.56	1,080,454.83	1	(31,644.81)	1,048,810.02	
75 Taxes	3,151.46	12,521.17			15,672.63	5	(878.38)	14,794.25	
76 Administration and general expense.	174,597.59	250,371.41			424,969.00	2	(163.20)	424,805.80	
77 Interest	603,060.38				603,060.38	3	(19,848.74)	583,211.64	
80 Earnings and expenses	(2,025.02)	(91.58)			(2,116.60)			(2,116.60)	
	1,846,925.67	259,392.01		15,722.56	2,122,040.24		(52,535.13)	2,069,505.11	
Indirect and overhead costs	2,203,763.45	2,459,850.26		(44,185.79)	4,619,427.92		(52,875.25)	4,566,552.67	
Total	19,757,269.72				19,757,269.72		(54,760.52)	19,702,509.20	

(A) Account references are to account numbers and titles prescribed in the Commission's Uniform System of Accounts effective prior to Jan. 1, 1961.
( ) Denotes negative figures.

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Project plant changes for period Nov. 1, 1954 through Dec. 31, 1958

Account number and title (A)	Allowed cost as of Oct. 31, 1954	Changes from Nov. 1, 1954 through Dec. 31, 1958				Total allowed cost as of Dec. 31, 1958
		As recorded			Staff recommended allowance	
		Per books	Eliminations (B)	Per books, as adjusted		
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Hydraulic production plant:						
320 Land and land rights	$1,707,968.53	($569,384.84)	$607,570.24	$38,185.40	$38,185.40	$1,746,153.93
321 Structures and improvements	1,999,644.05	249,283.27	(232,532.61)	16,750.66	16,750.66	2,016,394.71
322 Reservoirs, dams, and waterways	9,692,778.18	419,306.32	(423,195.90)	(3,889.58)	(3,889.58)	9,688,888.60
323 Water wheels, turbines, and generators	3,620,228.67	(24,326.53)	38,353.36	14,026.83	14,026.83	3,634,255.50
324 Accessory electric equipment	271,774.68	32,310.28	(10,440.96)	21,869.32	21,869.32	293,644.00
325 Miscellaneous power plant equipment	222,307.02	(7,529.49)	9,015.22	1,485.73	1,485.73	223,792.75
326 Roads, railroads, and bridges	187,034.14	24,994.74	(24,994.74)			187,034.14
Total hydraulic production plant	17,701,735.27	124,653.75	(36,225.39)	88,428.36	88,428.36	17,790,163.63
Transmission plant:						
340 Land and land rights	27,356.55	(19,265.33)	19,265.33			27,356.55
341 Clearing land and rights-of-way	2,757.52	(976.85)	976.85			2,757.52
342 Structures and improvements	87,995.88	(1,150.50)	1,150.50			87,995.88
343 Station equipment	538,122.04	(56,285.00)	57,371.23	1,086.23	1,086.23	539,208.27
344 Towers and fixtures	115,787.99	3,585.77	(2,506.98)	1,078.79	1,078.79	116,866.78
345 Poles and fixtures	502,571.30	(15,396.94)	15,396.94			502,571.30
346 Overhead conductors and devices	724,779.59	43,417.75	(43,417.75)			724,779.59
349 Roads and trails	1,403.06	(204.14)	204.14			1,403.06
Total transmission plant	2,000,773.93	(46,275.24)	48,440.26	2,165.02	2,165.02	2,002,938.95
100.1 Total electric plant in service	19,702,509.20	78,378.51	12,214.87	90,593.38	90,593.38	19,793,102.58

( ) Denotes credit.

(A) Account references are to account numbers and titles prescribed in the Commission's Uniform System of Accounts effective prior to Jan. 1, 1961.

(B) Closings to plant made from Nov. 1, 1954 to Dec. 31, 1954, but included in claimed cost as of Oct. 31, 1954 ($42,545.65)

Company entries adjusting books to FPC allowed cost as of Oct. 31, 1954 54,760.52

12,214.78

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

ARKANSAS LOUISIANA GAS COMPANY, ET AL., DOCKET NO. G–16125, ET AL.*

ORDER REQUIRING REFUNDS IN CERTAIN PROCEEDINGS AND TERMINATING ALL PROCEEDINGS

(Issued March 5, 1962)

Respondents in the above-entitled proceedings have heretofore filed proposed increased rates solely reflecting reimbursement for the additional gas gathering tax of one cent per Mcf imposed upon said respondents, effective August 1, 1958, by the State of Louisiana pursuant to Section 678 of Title 47 of the Louisiana Revised Statutes.[1] Respondents' proposed rates were suspended for one day and thereafter permitted to go into effect subject to refund of the increase in the event the tax was subsequently invalidated. On November 17, 1958, the Louisiana legislature suspended the operation of the gathering tax, effective December 1, 1958, and early in 1960 the Louisiana Supreme Court held the tax unconstitutional. *Bel Oil Corp. et al.* v. *Rufus W. Fontenot, Collector*, 238 La. 1002, 117 S. 2d 571; *Southern Natural Gas Co.* v. *Robert Q. Roland, Collector of Revenue*, 240 La. 471, 123 S. 2d 891.

On February 13, 1961, the Commission, without prior notice and without hearing, issued an order requiring respondents in all of the above proceedings to refund to their respective purchasers the amounts collected subject to refund under the Commission's original suspension orders. A timely application for rehearing of the February 13 order was filed by Arkansas Louisiana Gas Company, in Docket No. G–16125, and by order issued April 13, 1961, such application was granted by the Commission.

By order issued June 6, 1961, again without notice to potentially interested parties, and again without hearing, the Commission modified its February 13 order to provide in effect that rate refunds would be required of respondents only to the extent that respondents were able to obtain corresponding tax refunds from the State of Louisiana.

On July 5, 1961, Texas Gas Transmission Corporation (Texas Gas) and on July 6, 1961, the Memphis Light, Gas, and Water Division (Memphis) filed petitions seeking leave to intervene in Olin Gas Transmission Corporation (Olin), Docket No. G–15695, and concurrently therewith both companies tendered applications for rehearing of the said June 6, 1961, order, insofar as that order was applicable to said Docket No. G–15695.[2]

By order issued August 30, 1961, the Commission reopened all of the above-entitled proceedings and permitted Texas Gas and Memphis to intervene in Docket No. G–15695. The order also authorized all parties to file statements of position with respect to the controverted issues.

On November 15, 1961, the Commission issued and caused to be published in

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*As noted in Appendix A hereof under columns entitled "Docket Nos." and "Respondents".

[1] Act No. 8, approved June 16, 1958, 47 La. Rev. Stat. 1950, § 678. The additional tax imposed by Section 678 was intended as a temporary supplement to the existing gathering tax of one cent per Mcf, imposed under 47 La. Rev. Stat. 1950, § 671, which had been in effect since June 22, 1954.

[2] Texas Gas is a direct purchaser from Olin and a direct supplier of Memphis.

the Federal Register a notice fixing December 8, 1961, as the deadline for filing petitions to intervene in these proceedings. As a result, a petition to intervene in certain proceedings was filed on December 5, 1961, by Southern Natural Gas Company (Southern).

For reasons fully elaborated in our order issued today terminating the proceedings in Texaco Inc., *et al.*, Docket Nos. G–15546, *et al.*, which involved identical legal issues in connection with the Louisiana gathering tax, we are convinced that Texas Gas and Memphis took appropriate steps to preserve their standing in Docket No. G–15695, that the Commission was not justified in reopening any of the other dockets involved herein, and that the petition for intervention filed by Southern Natural Gas Company on December 5th was untimely. Accordingly, we shall vacate the August 30 order insofar as it reopened proceedings other than Docket No. G–15695, and shall reject as untimely Southern's petition for intervention. In taking this action, however, we do not intend, and should not be construed, to foreclose any party from seeking whatever relief, if any, may be appropriate under state law. Cf. *Pan American Petroleum Corp.* v. *Superior Court*, 366 U.S. 656 (1961).

In the aforesaid order issued today by which we dispose of the proceedings in Docket Nos. G–15546, *et al.*, we presented in considerable detail the grounds for our conclusion that respondents who declined to pay the Louisiana gathering tax under protest, and who thereby failed to qualify for tax refund from the State of Louisiana, should not for that reason be exempt from the duty to refund tax reimbursement amounts to their customers. On the grounds therein stated, we shall require Olin to refund the amounts collected, subject to refund, in Docket No. G–15695 under Rate Schedule P–2, the only schedule which is applicable to Texas Gas.

The Commission finds:

(1) Good cause has been shown for vacating the August 30, 1961, order insofar as it reopened the proceedings in Appendix A, other than the proceeding in Docket No. G–15695.

(2) The petition to intervene filed on December 5, 1961, by Southern should be rejected as untimely.

(3) It is in the public interest and necessity in the effective administration of the Natural Gas Act that the increased rates reflected in 2nd Revised Sheet No. 7 to FPC Gas Tariff, Original Vol. No. 1 (Rate Schedule P–2), involved in Docket No. G–15695, be disallowed, and refunds be made to Texas Gas.

The Commission orders:

(A) The increased rates identified in Finding (3), involved in Docket No. G–15695, are disallowed, and Olin shall refund to Texas Gas the amounts collected under the agreements and undertakings filed by Olin in compliance with the Commission's suspension orders herein, together with a proportionate part of any interest received from the State of Louisiana.

(B) Within 90 days from the date of issuance of this order, Olin shall, if it has not already done so, report to the Commission, in writing and under oath, the details of its calculations resulting in the refunds to be made pursuant to paragraph A hereof, together with copies of releases from Texas Gas with respect to such refund.

(C) The August 30, 1961, order is hereby vacated insofar as it reopened the proceedings in Appendix A hereto, other than the proceeding in Docket No. G–15695.

(D) The petition to intervene filed on December 5, 1961, by Southern is hereby rejected as untimely.

(E) The proceedings listed in Appendix A hereto are hereby terminated.

APPENDIX A

Respondent	*Docket Nos.*
Arkansas Louisiana Gas Company	G–16125
Mississippi River Fuel Corporation	G–15880
Mississippi River Fuel Corporation	G–16027
Mississippi River Fuel Corporation	G–16468
Olin Gas Transmission Corporation	G–15695
Southern Natural Gas Company	G–15882
Tennessee Gas Transmission Company	G–15567
Tennessee Gas Transmission Company	G–15649
Tennessee Gas Transmission Company	G–15736
Tennessee Gas Transmission Company	G–15881
Tennessee Gas Transmission Company	G–16247
Tennessee Gas Transmission Company	G–16251
Tennessee Gas Transmission Company	G–16486
Tennessee Gas Transmission Company	G–16692
Tennessee Gas Transmission Company	G–16707
Tennessee Gas Transmission Company	G–16708
Tensas Gas Gathering Corporation	G–16126

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CENTRAL NATURAL GAS COMPANY, DOCKET NO. CP62–71

FINDINGS AND ORDER DIRECTING PHYSICAL CONNECTION OF FACILITIES AND SALE OF NATURAL GAS

(Issued March 5, 1962)

On September 20, 1961, as supplemented on December 8, 1961, Central Natural Gas Company (Applicant) filed in Docket No. CP62–71 an application pursuant to Section 7(a) of the Natural Gas Act for an order of the Commission directing Northern Natural Gas Company (Northern) to establish physical connection of its facilities with those which Applicant proposes to construct and operate, and to sell and deliver to Applicant natural gas for resale and distribution in the Villages of Afton, Lakeland, Lakeland Shores, Lake St. Croix Beach and St. Mary's Point, in Washington County, Minnesota, all as more fully set forth in the application, as supplemented.

Applicant proposes to construct regulator stations at Afton, Lakeland and Lake St. Croix Beach, and distribution systems in all five of the communities named above, which communities have granted franchises for the proposed service. The estimated total investment in the subject facilities at the end of the third year of operation is $99,940, which Applicant proposes to finance through a temporary bank loan and the subsequent issue of bonds and preferred stock.

The estimated natural gas requirements of the communities involved herein are:

	1st year	2d year	3d year
Annual (Mcf)	34,200	43,720	51,600
Peak day (Mcf)	288	382	460

Northern Natural Gas Company filed its answer to the subject application on October 23, 1961, stating that it does not oppose said application and is willing to render service for the five proposed communities. Applicant has shown that no increase in its authorized contract demand from Northern will be required inasmuch as its existing manufactured gas peak shaving equipment at Hastings, Minnesota, is capable of increased output sufficient to assure Applicant's meeting its customer requirements, including those of the third year for the five towns under the instant application, within its presently authorized contract demand.

Northern's meter station which will be used for the service hereinafter authorized was constructed under its budget-type authorization granted in Docket No. CP61–34 for service to existing markets.

There is no question as to gas supply.

Due notice of the filing of the subject application and opportunity for hearing thereon has been given by publication in the Federal Register on January 25, 1962 (27 FR 758). No protest or petition to intervene has been filed in this proceeding.

The Commission finds:

(1) Northern Natural Gas Company, a Delaware corporation having its principal place of business in Omaha, Nebraska, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G–280 (3 FPC 967).

(2) Applicant, Central Natural Gas Company, a Delaware corporation having its principal place of business in Vermillion, South Dakota, is duly authorized to sell and distribute natural gas in the State of Minnesota.

(3) It is necessary and desirable in the public interest to direct Northern to establish physical connection of its transmission system with the facilities which Applicant proposes to construct and operate and to sell and deliver, within Central Natural's authorized contract demand, natural gas for resale in Washington County, Minnesota, as hereinbefore described and as more fully described in the application, as supplemented in this proceeding.

(4) The requirement that Northern serve Applicant, as proposed herein, will not place an undue burden upon Northern nor impair its ability to render adequate service to its existing customers.

(5) The directive hereinafter issued should be conditioned upon Applicant's commencing taking of natural gas thereunder within one year from the date of issuance of this order.

The Commission orders:

(A) Northern Natural Gas Company be and it is hereby directed to establish physical connection of its transmission system with the facilities which Central Natural Gas Company proposes to construct and operate, and to sell and deliver, as part of Central Natural Gas Company's authorized contract demand, volumes

of natural gas, under Northern's appropriate gas rate schedules on file with the Commission, for resale in Washington County, Minnesota, as hereinbefore described and as more fully described in the application, as supplemented, in this proceeding, providing Central Natural Gas Company commences the purchase of such natural gas within one year from the date of issuance of this order.

(B) Northern shall report to the Commission in writing and under oath the date of commencement of service to Applicant hereunder within ten days of the commencement thereof.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TEXACO INC., ET AL.*, DOCKET NO. G–15546, ET AL.*

ORDER REQUIRING REFUNDS IN CERTAIN PROCEEDINGS AND TERMINATING ALL PROCEEDINGS [1]

(Issued March 5, 1962)**

Respondents in the above-entitled proceedings have heretofore filed proposed increased rates solely reflecting reimbursement for the additional gas gathering tax of one cent per Mcf imposed upon said respondents, effective August 1, 1958 by the State of Louisiana pursuant to Section 678 of Title 47 of the Louisiana Revised Statutes.[2] Respondents' proposed rates were suspended for one day and thereafter permitted to go into effect subject to refund of the increase in the event the tax was subsequently invalidated. On November 17, 1958, the Louisiana legislature suspended the operation of the gathering tax, effective December 1, 1958, and early in 1960 the Louisiana Supreme Court held the tax unconstitutional. *Bel Oil Corp. et al.* v. *Rufus W. Fontenot, Collector*, 238 La. 1002, 117 S. 2d 571; *Southern Natural Gas Co.* v. *Robert Q. Roland, Collector of Revenue*, 240 La. 471, 123 S. 2d 891.

On February 21, 1961, the Commission, without prior notice and without hearing, issued an order requiring respondents in all of the above proceedings to refund to their purchasers the amounts collected subject to refund under the Commission's original suspension orders. Timely applications for rehearing of the February 21 order were filed by respondents in the proceedings listed in Appendix B hereto,*** and by order of April 14, 1961 such applications were granted by the Commission.

By order issued May 29, 1961, again without notice to potentially interested parties and again without hearing, the Commission modified its February 21 order to provide in effect that rate refunds would be required of respondents only to the extent that respondents were able to obtain corresponding tax refunds from the State of Louisiana. The order also denied petitions to intervene

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*As noted in Appendix A hereof under columns entitled "Docket Nos." and "Respondents." [Appendix A omitted in printing.]

**Rehearing denied by orders issued April 13 and 26, 1962, 27 FPC 688 and 847. Orders issued June 1, 1962 and July 2, 1962, granting stay pending judicial review, 27 FPC 1106, and 28 FPC 8, respectively. See order on remand, 31 FPC 438. [See Pan American Petroleum Corp. v. F.P.C., 322 F. 2d 999 and Tennessee Gas Transmission Co. v. F.P.C., 322 F. 2d 1006 (CADC–1963).]

***Omitted in printing.

[1] This order does not provide for consolidation of the proceedings involved herein, nor should it be so construed.

[2] Act No. 8, approved June 16, 1958, 47 La. Rev. Stat. 1950, § 678. The additional tax imposed by Section 678 was intended as a temporary supplement to the existing gathering tax of one cent per Mcf, imposed under 47 La. Rev. Stat. 1950, § 671, which had been in effect since June 22, 1954.

which had been filed in March and April by Transcontinental Gas Pipe Line Corporation (Transco), Southern Natural Gas Company (Southern), and a group of four eastern distributing companies (Distributors).[3] As a corollary to this action, the Commission rejected a joint and several application for rehearing of the February 21 order tendered by the Distributors along with their petitions for intervention.

On June 28, 1961, Transco and United Fuel Gas Company (United Fuel), which had been admitted as an intervenor in some of the proceedings, filed applications for rehearing of the May 29 order in the dockets listed in Appendices C and D hereto,* respectively. The Commission took no action on the Transco and United Fuel applications within thirty days of their filing, and therefore such applications must be "deemed to have been denied." Transco, on July 28, 1961 and August 9, 1961, filed petitions for review of the May 29 order in the Court of Appeals for the District of Columbia Circuit (CADC Nos. 16510, 16538); United Fuel filed no petition for review.

On June 27, 1961, the Memphis Light, Gas and Water Division (Memphis), and on June 28, 1961, Texas Gas Transmission Corp. (Texas Gas), filed petitions seeking leave to intervene in the proceedings listed in Appendix E hereto, and concurrently therewith both companies tendered applications for rehearing of the said May 29, 1961 order.[4]

By order issued August 30, 1961, the Commission reopened all of the above-entitled proceedings and permitted the Distributors, Transco, Southern, Memphis, Texas Gas, and United Fuel to intervene in the proceedings designated in their respective petitions for intervention and for rehearing. The order also authorized respondents and intervenors to file statements of position with respect to the controverted issues.

By order issued October 31, 1961, the Commission denied motions by certain respondents for rehearing of the August 30, 1961, order, explaining that its decision to reopen all of the instant proceedings had been prompted by concern as to whether potentially interested parties had been given adequate notice of the Commission's earlier actions. To remedy any prior lack of notice, the Commission on November 6, 1961, issued and caused to be published in the Federal Register a notice fixing November 30, 1961, as the deadline for filing petitions to intervene in these proceedings. As a result, petitions to intervene in certain proceedings were tendered for filing within the prescribed deadline by Texas Eastern Transmission Corporation (Texas Eastern), Tennessee Gas Transmission Company (Tennessee), Southern, and United Fuel.[5]

Petitions for review of the order of August 30, 1961, have been filed by a number of respondents in the Court of Appeals for the Fifth Circuit and the Court of Appeals for the District of Columbia Circuit.[6]

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*Omitted in printing.

[3] Long Island Lighting Company, Public Service Electric and Gas Company, Philadelphia Electric Company, and The United Gas Improvement Company.

[4] Memphis sought intervention in proceedings which involve rates for gas purchased by Texas Gas, its direct supplier. Texas Gas sought intervention in proceedings which involve rates for gas purchased by it.

[5] The thirty-four dockets in which Southern petitioned to intervene on November 20, 1961, did not include any of the proceedings in which it had earlier sought intervention and been permitted to intervene by the order of August 30, 1961. United Fuel's petition of November 8, 1961, sought intervention in docket numbers G-13972, G-16042, and G-16070, in which it had earlier inadvertently omitted to intervene.

[6] Fifth Circuit Case Nos. 19403 (F. A. Callery, Inc.), 19395 (Hunt Oil Company et al.), 19399 (Sun Oil Company), 19401 (Placid Oil Company, J. R. Goff, Trustee); D. C. Circuit Case Nos. 16787 (Pan American Petroleum Corporation), 16794 (Sun Oil Company).

In their various statements of position, motions for reconsideration, and petitions for review, respondents have urged that the order of August 30, 1961, be vacated as to their respective proceedings, on the ground that the February 21, 1961 order, May 29, 1961, order, or both, are final orders and as such may not be reconsidered. They contend, among other things, that if an aggrieved party neglects to apply for rehearing and petition for court review of a Commission order in the manner prescribed by Section 19 of the Natural Gas Act (hereinafter called "the Act"), then the order becomes irrevocable as to all parties, including the Commission.

It is evident from the foregoing chronology that Transco, United Fuel, Memphis, and Texas Gas took appropriate steps to preserve their standing in these proceedings and are not dependent upon any *sua sponte* action of the Commission in order to qualify for a rehearing of the May 29 order. Transco filed a timely application for rehearing of the May 29 order denying its earlier petition for intervention, and when the Commission failed to act on such application within thirty days, filed a timely petition for review. Since the record in our proceedings has not yet been filed in the Court of Appeals, we still retain jurisdiction under Section 19(a) of the Act to affirm, modify, or set aside our May 29 order.

United Fuel, already admitted as an intervenor, likewise filed a timely application for rehearing of the May 29 order, and its subsequent omission to seek court review did not affect its standing before the Commission. It is true that by virtue of our failure to act upon United Fuel's application within thirty days, such application must, under Section 1.34(c) of the Commission's Rules of Practice and Procedure, be "deemed to have been denied." That section, however, the sole purpose of which was to establish a definite commencement date for the running of the sixty day period within which to petition for judicial review under Section 19(a) of the Act,[1] was not intended and cannot be construed to disable the Commission from granting an application for rehearing later than the thirtieth day after its filing. In any event, the order of August 30, reopening all proceedings, was issued prior to the expiration of the sixty day period for filing a petition for review. Section 19(a) of the Act provides that "until the record in a proceeding shall have been filed in a court of appeals * * * the Commission may at any time * * * modify or set aside, in whole or in part, any filing or order made or issued by it under the provisions of this Act." If the Commission retains jurisdiction to modify a prior order, and perhaps render litigation unnecessary, even after a petition for review of that order has been filed, then by reasonable inference it must also have such jurisdiction, absent a petition for review, during the period in which such petition would be timely and no reliance could legitimately be placed on the finality of the prior order.

Memphis and Texas Gas filed petitions to intervene and tendered applications for rehearing less than thirty days after the May 29 order, and by such action preserved their standing. Respondents argue that such petitions were untimely because filed after the issuance of final orders terminating the proceedings.

[1] Section 19(a) of the Act provides that an application for rehearing which is unacted upon for thirty days "*may* be deemed to have been denied." (Emphasis added). In *Texas-Ohio Gas Co.* v. *Federal Power Comm.*, 207 F. 2d 615 (D.C. Cir. 1953), it was held that because of the indefiniteness of the statutory language, the sixty day limitations period for filing petitions for review would not commence to run absent a general rule of the Commission that thirty-day inaction "*shall*" be deemed denial. Shortly thereafter, the Commission adopted Section 1.34(c) in order to avoid a repetition of the result in the *Texas-Ohio* case.

This contention, however, overlooks the fact that prior to May 29, 1961, Memphis and Texas Gas had not been aggrieved, nor their right to a refund placed in doubt, by any order of the Commission, and that the Commission had neither held hearings, invited statements of position, nor fixed a time for intervention. Under these circumstances, it was not untimely for Memphis and Texas Gas to seek intervention subsequent to the May 29, 1961, order as a means of submitting timely applications for rehearing thereof.

With respect to all other proceedings, the action taken by the Commission in its August 30, 1961, order was *sua sponte* and, as explained in our October 31, 1961, order, was prompted by concern as to whether potentially interested parties had been given adequate notice and opportunity to be heard prior to May 29, 1961. Careful restudy of the intricate history of these proceedings has satisfied us that lack of formal notice prior to the May 29 order did not irreparably prejudice any party now before the Commission. Southern and the Distributors were obviously not prejudiced, since they filed timely petitions for intervention subsequent to the February 21 order. Upon denial of those petitions, their proper course was to apply within 30 days for a rehearing of the May 29 order. *Public Service Commission of New York* v. *Federal Power Commission*, 284 F. 2d 200, 204 (D.C. Cir. 1960). Texas Eastern, Tennessee, United Fuel, and Southern—all of which filed petitions to intervene during the month of November, 1961—are direct purchasers of respondents, and as such were routinely served with copies of the May 29 order.[3] They, too, had ample opportunity to seek intervention and/or rehearing but neglected to do so. It might be added, moreover, that each of the above pipelines was served with a copy of the April 14, 1961 order granting rehearing to certain of the respondents. Such notice was sufficient to alert the purchasers that the Commission was contemplating modification of its February 21 order and that the refund seemingly promised them by said order was in jeopardy. Although failure of the November petitioners to seek intervention and/or rehearing prior to May 29 did not bar them from doing so promptly thereafter, their protracted lack of diligence both before and after the controverted order prevents us from extending them grace at this late date.

In light of the preceding considerations, we shall vacate the August 30 order insofar as it permitted intervention by Southern and the Distributors and insofar as it reopened proceedings other than those designated in Appendices C, D, or E hereto. Additionally, we shall reject as untimely the petitions for intervention filed in November, 1961, by Texas Eastern, Tennessee, Southern and United Fuel. In taking this action, however, we do not intend and should not be construed to foreclose any party from seeking whatever relief, if any, may be appropriate under state law. Cf. *Pan American Petroleum Corp.* v. *Superior Court*, 366 U.S. 656 (1961).

We consider now the ultimate substantive issue raised by these proceedings, i.e., whether respondents who declined to pay the tax under protest and thereby failed to qualify for a tax refund from the state of Louisiana should be exempted from the duty to refund tax-reimbursement amounts to their customers. The answer to this question depends, in part at least, upon the meaning of the Commission's original orders in 1958. On July 11, 1958, anticipating that the new Louisiana tax would trigger rate filings based upon tax-reimbursement clauses in the producers' contracts with the pipelines, the Commission issued Order No. 206, 20 FPC 28, in which it prescribed a simplified procedure for filing proposed

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[3] It is the Commission's practice to serve direct purchasers with copies of all orders relating to action taken with respect to their suppliers.

rate increases based on the tax, waived the 30 day notice requirement for such filings, and announced that it would suspend such rates for one day and then permit them to go into effect subject to refund. Proposed rates filed pursuant to Order No. 206 were suspended for one day by identical orders[8] issued in each docket, the pertinent terms of which were as follows:

> (D) Respondent shall refund at such times and in such amounts to the persons entitled thereto, and in such manner as may be required by final order of the Commission, the difference between the presently effective rate and charge and the proposed increased rate and charge hereby allowed to become effective in the event the additional tax of 1 cent per Mcf levied by the State of Louisiana is for any reason held to be invalid. Should such additional tax eventually be held invalid and the State of Louisiana make refund, with interest, of the tax monies collected pursuant to the said Act No. 8 of 1958, then, and in that event, a proportionate part of the interest so received by the respondent herein shall be passed on and paid to the persons entitled thereto at such times and in such amounts, and in such manner as may be required by final order of the Commission.

From the first sentence of the above paragraph it is clear that the obligation to refund the difference between the "presently effective rate" and the "proposed increased rate" was contingent solely upon the judicial invalidation of the tax. It was only the duty to refund *interest*, under the second sentence, which was made to depend upon the receipt by respondents of a refund from the state. A contingency carefully written into the second sentence cannot reasonably be deemed implicit in the first, from which it was omitted. Confronted also by an order in terms exposing them to refund obligations regardless of whether they were made whole by the state, respondents could have moved for reconsideration of the suspension orders or otherwise sought clarification from the Commission. In failing to do so they assumed the risk that the Commission's orders meant what they said.

In support of a contrary interpretation, respondents rely upon two letters from the Commission to the Collector of Revenue of the State of Louisiana, dated October 2, 1958, and October 28, 1958, respectively, and published in Commission press releases. The same letters were also cited by the Commission itself—misguidedly, we now concede—in the May 29 order. It is elementary that the obligations of parties subject to regulation by this Commission are governed by the plain language of its official orders, not by its subjective intent as expressed in collateral correspondence made public in press releases. However, even if the suspension orders were so ambiguous as to require extrinsic illumination, we should still not regard the particular letters in question as persuasive glosses. While certain language in the letter of October 2 does seem to suggest that respondents' refund obligation should be limited to amounts actually received from the state, an opposite conclusion is inferable from the letter of October 28, the core of which was as follows:

> Neither this general order nor the orders subsequently adopted in accordance with its terms suggested in any way that a suit should be brought to test the validity of the Louisiana gathering tax, *but merely sought to protect ultimate consumers in a proper manner against payment of operating expenses which included the tax if the tax is held to be invalid.*

Indeed, in Opinion No. 278, El Paso Natural Gas Company, Docket No. G–2018, issued November 26, 1954 (13 FPC 421), the Commission refused

[8] See, *e.g.*, *Shell Oil Company (Operator)*, Docket No. G–15552, 20 FPC Reports 105 (July 30, 1958).

to allow as an operating expense a payment by El Paso of a somewhat similar tax under a Texas statute subsequently declared invalid, notwithstanding the failure of El Paso to make its tax payments to the State under protest. A similar ruling was made in Opinion No. 269, Panhandle Eastern Pipe Line Company, issued April 15, 1954 (13 FPC 53).

The Federal Power Commission has no desire to force the testing of a State statute and it is not doing so in the present instance. Nevertheless, before adopting Order No. 206, *it was advised by a number of pipeline companies subject to the Natural Gas Act that they intended either to test the Louisiana gathering tax or would see that a test suit was filed. Therefore, in order to protect ultimate consumers against imposition of tax expense held to be unlawful, some steps had to be taken along the lines of Order No. 206 and the orders subsequently issued thereunder.* Some of the companies which previously advised the Commission that the Louisiana law would be tested in court have again advised the Commission to the same effect. Under these circumstances it would not appear appropriate to amend Order No. 206. [Emphasis added.]

Citation of *El Paso Natural Gas Company*[10] in this context indicates that the Commission deemed it immaterial to the producers' refund obligation whether they paid the tax under protest or not. Moreover, in light of the advice received by the Commission that pipeline companies had already decided to test the statute, its disclaimer of any intent to "force" such test meant simply that Order No. 206 was a response to the prospect of litigation, not an attempt to bring litigation about. Such disclaimer carried no implication whatever that respondents who did not protect their right to a refund from the state would be exonerated from the duty to refund appropriate amounts to their customers.[11]

In view of the conflicting inferences to which the above letters give rise, they can scarcely be relied upon as guides to the interpretation of the suspension orders. The same must be said of various orders, cited by respondents, granting certificates of public convenience and necessity in proceedings involving the Louisiana gas gathering tax as part of the initial rate, and expressly conditioning the applicants' refund obligations upon the payment to them of tax refunds by the state.[12] Whether the absence of a comparable condition in the instant rate suspension orders was the result of inadvertence or policy, the fact remains that the Commission cannot be deemed to have implied by silence in the rate orders what it took pains to spell out in the certificate orders.

It is possible that the suspension orders were not intended to fix conclusively the scope of respondents' refund obligation, but instead reserved that matter for later determination by final orders of the Commission. If so, then whatever

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[10] Opinion No. 278, Docket No. G-2018, 13 F.P.C. 421, 486. See *Panhandle Eastern Pipe Line Company*, Docket No. G-1116, *et al.*, 13 F.P.C. 53, 103. Cf., *Tennessee Natural Gas Line, Inc.* v. *F.P.C.*, 221 F. 2d 531 (D.C. Cir. 1954).

[11] Under Louisiana law, payment under protest does not oblige the taxpayer to file a suit, so long as he shows that litigation involving the validity of the assessment is already pending in the courts and so long as he agrees to abide by the results of such litigation, 47 La. Rev. Stat., § 1576. Actually, *Bel Oil Corp.* v. *Pontenot, supra*, the case in which the gathering tax was eventually struck down, had been pending in the 19th Judicial District Court, East Baton Rouge Parish, since December 6, 1954. (Docket No. 51809). Therefore, it would not have been necessary for any producer to "test" the statute in order to preserve its right to a refund.

[12] See, *e.g.*, *Transcontinental Gas Pipe Line Corporation, et al.*, Docket Nos. G-13143, *et al.*, Opinion No. 315, issued September 4, 1958, 20 FPC 264 at 285; *Texas Gas Transmission Corp., et al.*, Docket Nos. G-14494, *et al.*, order issued December 4, 1958; *American Louisiana Pipe Line Company, et al.*, Docket No. G-15053, *et al.*, order issued November 7, 1958.

discretion the Commission retained was exercised in the order of February 21, which once again required refunds of all producers without hint of qualification. The chief ordering clause of that order provided as follows:

> (A) The above-designated increased rates are disallowed and Respondents shall refund their respective purchasers the amounts collected under the respective agreements and undertakings filed in compliance with the Commission's orders herein together with a proportionate part of any interest received from the State of Louisiana.

The above clause was later modified by the order of May 29, 1961. For present purposes we need not decide whether such modification was inconsistent with the mandate contained in the original suspension orders or whether it fell within the range of discretion left open by such orders. In either case it still lies within our discretion to reimpose the unqualified refund obligation originally embodied in the February 21 order, and upon full consideration of the competing equities involved herein, we deem such imposition appropriate.

By the time the Section 678 tax had become effective, litigation testing the validity of the Louisiana gathering tax was already before the courts;[13] the Commission's suspension orders had in terms prescribed a duty to repay purchasers if the tax were held invalid; and, in many instances, the pipelines had written the producers, cautioning or demanding them to pay the tax under protest.[14] Thus, respondents were amply forewarned of the consequences they invited in refusing to register protests. Such refusal cannot be justified on the ground that payment under protest would have launched respondents into immediate litigation or would have encouraged the State of Louisiana to raise its severance tax in order to replace lost revenues. Since litigation to challenge the gathering tax was already pending, no protesting producer would have been forced to initiate a test case.[15] Moreover, the degree of likelihood that Louisiana would respond by raising the severance tax (a point on which no evidence has been presented), and if so, whether forfeiture of the gathering tax refund would have yielded a net benefit to the purchasers and consumers who would eventually have had to pay a large part of the tax, were not questions of unilateral concern to respondents. At the very least, it was incumbent upon them to consult with and seek the approval of the purchasers for the course they proposed to follow.[16] The purchasers themselves had no standing under Louisiana law to protest the assessments and were entirely dependent upon their respective suppliers to protect their interests. Some producers paid the tax under protest; others, either through negligence or conscious policy, did not protest. Under all the circumstances, we see no justification for burdening pipeline, distributor, or consumers with the consequences of a unilateral decision by the producer, heedless, in many cases, of the express admonitions of its customers.

Many of the instant proceedings involve sales by a respondent to more than one purchaser under different rate schedules. It is argued by respondents that the May 29 order should be revised and refunds ordered only with respect to rate schedules or supplements involving a direct or secondary purchaser which

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[13] See f.n. 11, *supra*.

[14] See, *e.g.*, Southern's Statement of Position, pp. 14–15; Transco's Statement of Position, p. 10; Texas Gas's Statement of Position, p. 4; United Fuel's Statement of Position, p. 4.

[15] See f.n. 11, *supra*.

[16] It may well be that respondents were under a legal duty to preserve the rights of their customers to recover the invalid taxes, and that they could be held to account for breach of that duty, even if the Commission's suspension order had required refund only of such amounts as were actually recovered from the state. Cf. *Natural Gas Pipeline Co.* v. *Harrington*, 246 F. 2d 915 (5th Cir. 1957).

has been properly permitted to intervene and whose petitions to intervene or application for rehearing was the basis for reopening the docket. We agree with this contention and accordingly shall require respondents in proceedings listed in Appendices C through E hereto, respectively, to refund amounts collected subject to refund under rate schedules applicable to Transco, United Fuel, and Texas Gas.

Several of the intervenors have taken the position that their contracts obligate them to reimburse their respective suppliers only for valid taxes, and therefore, under *United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.*, 350 U.S. 332 (1956) the Commission has no choice but to order refunds. Having decided on other grounds to order refunds, we deem it unnecessary to pass upon the *Mobile* question or to construe the tax reimbursement provisions of the subject contracts.

One additional matter needs to be settled. Union Oil Company of California (Union) claims that the issue of reimbursement for the additional gathering tax in Docket Nos. G–15846 and G–15847 was covered by Union's offer of settlement, accepted by the Commission in its order of January 13, 1960, in Docket Nos. G–4331, *et al.*, 23 FPC 73. That settlement order, however, did not purport to apply to Docket Nos. G–15846 and G–15847. Moreover, by order issued March 17, 1960 in Docket Nos. G–4331, *et al.*, the Commission accepted for filing the superseding rate schedule supplements of Union, tendered in compliance with the said order of January 13, 1960, upon condition that such acceptance would not impair Union's obligation to refund to Transco the .75¢ per Mcf Louisiana gathering tax reimbursement subject to refund in Docket Nos. G–15846 and G–15847. Accordingly, we believe that Union should be required to refund the amounts collected, subject to refund, in Docket Nos. G–15846 and G–15847.

The Commission finds:

(1) Good cause has been shown for vacating the August 30, 1961, order insofar as it reopened the proceedings in Appendix A, except for those proceedings listed in Appendices C through E inclusive, and insofar as it permitted Southern and the Distributors to intervene in certain proceedings.

(2) The petitions to intervene filed in November 1961 by Texas Eastern, Tennessee, Southern, and United Fuel should be rejected as untimely.

(3) It is in the public interest and necessity in the effective administration of the Natural Gas Act that the supplements filed in the proceedings listed in Appendices C through E hereof with respect to sales of gas to Transco, United Fuel, or Texas Gas be disallowed, and that refunds be made to said purchasers.

The Commission orders:

(A) The increased rates reflected in the rate supplements applicable to Transco, United Fuel, and Texas Gas in the proceedings designated in finding (3) above are disallowed and respondents in such proceedings shall refund to said purchasers the amounts collected under the respective agreements and undertakings filed in compliance with the Commission's suspension orders herein, together with a proportionate part of any interest received from the State of Louisiana.

(B) Any purchaser which receives a refund pursuant to paragraph (A) hereof, and which is obligated by the terms of any contract or settlement agreement to pass all or any part of such refund on to its customers, shall promptly make such refund to its customers in compliance with the terms of such contract or settlement agreement.

(C) Within 90 days from the date of issuance of this order, each respondent designated in paragraph (A), if it has not already done so, shall report to the

Commission, in writing and under oath, the details of its calculations resulting in the refunds to be made pursuant to paragraph (A) hereof, together with copies of releases from its customers with respect to such refund.

(D) Within 120 days from the date of issuance of this order, each purchaser designated in paragraph (B), if it has not already done so, shall report to the Commission, in writing and under oath, the details of its calculations resulting in the refunds to be made pursuant to paragraph (B) hereof, together with copies of releases from its customers with respect to such refund.

(E) The August 30, 1961 order is hereby vacated insofar as it reopened the proceedings in Appendix A hereto, except for those proceedings listed in Appendices C through E hereto, and insofar as it permitted the Distributors and Southern to intervene in certain proceedings.

(F) The petitions to intervene filed in November, 1961, by Texas Eastern, Tennessee, Southern, and United Fuel are hereby rejected as untimely.

(G) The proceedings listed in Appendix A hereof are hereby terminated by the Commission.

MICHIGAN WISCONSIN PIPE LINE COMPANY, DOCKET NO. CP61–102; PAN AMERICAN PETROLEUM CORPORATION, DOCKET NO. CI61–516; SHELL OIL COMPANY, DOCKET NO. CI61–524; SINCLAIR OIL AND GAS COMPANY, DOCKET NO. CI61–691; WILCOX OIL COMPANY, DOCKET NO. CI61–717; THE ATLANTIC REFINING COMPANY, DOCKET NO. CI61–752; KERR-McGEE OIL INDUSTRIES, INC., DOCKET NO. CI61–785; SKELLY OIL COMPANY, DOCKET NO. CI61–819; WOODSON OIL COMPANY, DOCKET NO. CI61–996; AMERADA PETROLEUM CORPORATION, DOCKET NO. CI61–1091; SUN OIL COMPANY, DOCKET NO. CI61–1102; J. M. HUBER CORPORATION, DOCKET NO. CI61–1146; SUNRAY MID-CONTINENT OIL COMPANY, DOCKET NO. CI61–1147.

OPINION AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 7, 1962)*

Syllabus

1. *Panhandle* case (Op. No. 350) found controlling with respect to determination of price and area questions in this proceeding. P. 454.
2. Evidence of comparative costs and of geological, operating and marketing characteristics of Woodward area is not of such compelling nature as to cause Commission to depart from pricing pattern established in *Policy Statement*. P. 454.
3. Until such time as Woodward area develops to extent that area hearing may be utilized to determine area prices, or evidence of necessity of *ad hoc* adjustment is more compelling than here, Commission will adhere to ceiling levels set forth in *Policy Statement*. P. 454.
4. Commission conditions producer certificates at initial wellhead price of 17 cents per Mcf for sales in Panhandle area, and 15 cents for sales in "other" Oklahoma area. P. 454.
5. Should current study of area boundaries result in any increase in area price levels applicable to sales herein certificated, producers may substitute new rates consistent with their contracts reflecting such increase and collect new rates prospectively in lieu of initial rates herein required. P. 454.

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*Designated Commission Opinion No. 353; Initial decision appears on p. 464.

6. Commission *allows* 100 percent take-or-pay provision proposed by producers subject to ultimate disposition with respect thereto in rulemaking proceeding (R–199). P. 454.
7. Prepayment provisions of Michigan Wisconsin contracts *allowed:* Commission finds such arrangements represent reasonable solution to Michigan Wisconsin's need for large, flexible new supply; such increased costs to jurisdictional customers as may reasonably be expected to result therefrom will not be excessive; and benefits to all concerned, including jurisdictional customers, justify such allowance. P. 455.
8. Commission *rejects* Staff contention that initial prices be for gas dehydrated in accordance with standard for pipeline quality gas proposed in Docket No. R–200; finds nothing in this record to show that proposed sales are not of pipeline quality-gas as that term is generally understood in these pricing areas. P. 461.
9. Commission *issues* certificates of public convenience and necessity to producer applicants and Michigan Wisconsin under Section 7 of the Natural Gas Act. P. 462.

Robert E. May, Louis Flax and Charles V. Shannon for Michigan Wisconsin Pipe Line Company.

Clifford O. Stone, Jr., William J. Grove, John F. Jones, and *Norton Standeven* for Pan American Petroleum Corporation.

Oliver L. Stone and *Joseph C. Spalding* for Shell Oil Company.

Charles E. McGee, James O. McKinney, Jr., Angus Davidson and *Francis O. H. Searle* for Sinclair Oil & Gas Company.

Glenn R. Davis for Wilcox Oil Company.

Charles B. Ellard, Bernard A. Foster, Jr., and *Sherman S. Poland* for The Atlantic Refining Company.

Jack T. Conn and *William Amory Underhill* for Kerr-McGee Oil Industries, Inc.

David M. Cook and *Sherman S. Poland* for Skelly Oil Company.

Joseph C. Spalding for Woodson Oil Company.

Robert J. Stanton and *Kenneth Scott* for Amerada Petroleum Corporation.

J. O. Dean, G. H. Bowan, W. C. Phelps, John A. Ward, III, and *Stanley M. Morley* for Sun Oil Company (Mid-Continent Division).

Thomas O. Moxcey for J. M. Huber Corporation.

H. E. McEwen, Jr., and *Dale E. Doty* for Sunray Mid-Continent Oil Company.

William E. Torkelson for Wisconsin Public Service Commission.

Rueben Goldberg and *George Spiegel* for Michigan Gas and Electric Company.

Robert L. Russell and John J. Keating, Jr. for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

O'Connor, *Commissioner:*

This is a certificate proceeding under Section 7 of the Natural Gas Act involving applications by Michigan Wisconsin Pipe Line Company (Michigan Wisconsin) and twelve natural gas producers. Michigan Wisconsin desires to construct and to operate a supply lateral and gathering facilities which will enable it to receive gas which it has contracted to purchase from the producers in the Woodward area of northwest Oklahoma and to transport this gas to its existing main line some 97 miles to the north. The producers propose to sell this gas to Michigan Wisconsin under 20-year contracts at a base initial wellhead price of 19.5 cents per Mcf,[1] with periodic escalations of 2.5 cents per Mcf every

[1] All prices referred to herein are at 14.65 psia.

five years. In addition to the base price, the contracts provide for an upward adjustment of 1/100 per cent Mcf for each Btu of heat content in excess of 1,000 Btu's per cubic foot, but not over 1,200 Btu's per cubic; as well as for reimbursement of 100 percent of the producers' present production, gathering, severance, and similar taxes, plus 75 percent of the new or increased future taxes.

The proposals in this case are not part of an expansion of the Michigan Wisconsin system, but are for the purpose of providing a gas supply to offset an anticipated decline in gas supply from Michigan Wisconsin's principal supplier, Phillips Petroleum Company (Phillips). Under its contracts with Phillips, Michigan Wisconsin is obligated to purchase its first 343,000 Mcf of gas from Phillips so long as Phillips is able to maintain deliverability. As the record shows, Phillips will not be able to maintain full delivery of the 343,000 Mcf per day in 1963 and later years; and this drop-off will result in a daily average delivery of less than 300,000 Mcf in 1964, and less than 200,000 Mcf by 1967. Thus Michigan Wisconsin, which has no production of its own, is faced with the necessity of obtaining large new gas reserves which it can integrate with the decline in Phillips' deliveries so as to maintain the operation of its pipeline on a high load factor basis.

To meet the Phillips drop-off, Michigan Wisconsin has negotiated contracts with the producer applicants for the dedication of extensive reserves in the Woodward area. Under these contracts, the producers have committed a total of some 287,000 acres to Michigan Wisconsin, of which 17,900 acres with gas reserves of 238 million Mcf have been proven. To enable Michigan Wisconsin to integrate the deliveries of the Woodward area gas with the drop-off of its Phillips supply, the contracts contain flexible take provisions which give Michigan Wisconsin the right to defer its takes during the early years of the contracts, and to make up these deferred takes in later years. Thus Michigan Wisconsin may take as little as 25 percent (40 percent from Pan American) of the average daily contract quantities during the first three years, and make up the deficiencies over the life of the contracts (over 10 years from Pan American). Although it must currently pay for a daily minimum of 75 percent of the average daily contract quantities (the deficiencies being figured as 1,000 Btu gas), no additional payment, other than for Btu's in excess of 1,000, is required when Michigan Wisconsin actually takes delivery of the gas, regardless of when the deferred takes are made up.[2]

In addition to the foregoing provisions for the deferral of takes under its gas purchase contracts, Michigan Wisconsin has entered into supplemental agreements with the major producers for the prepayment of a one-year supply of gas computed on the basis of one Mcf per day for each 4,000 Mcf of presently proven reserves. In accordance with these agreements, such prepayments were made

[2] Apart from these special provisions for reduced takes during the first three years of the contracts, Michigan Wisconsin is required on any one day to take not less than 75 percent of the average daily contract quantities and not more than 125 percent of such quantities. Average daily contract quantities are computed on the basis of one Mcf per day for each 7,300 Mcf of recoverable reserves. Michigan Wisconsin is required to pay for 100 percent of these quantities on an annual basis. Thus, to the extent that there is a deficiency at the end of any year, Michigan Wisconsin must pay for such gas not taken at the price in effect at the end of the year plus a Btu adjustment based on the average Btu content of gas delivered during the year. Michigan Wisconsin, however, may make up these deficiencies over a period of four years, paying the difference between the price in effect when the gas is taken and the price already paid. To the extent that Michigan Wisconsin takes deliveries in excess of the average daily contract quantities, such excess is to be first imputed to the make-up of any accrued contract deficiencies under the provisions just described, and then to the make-up of any gas paid for but not taken under the special provisions for reduced takes during the first three years of the contracts.

in the amount of $4,040,928 upon the filing of the producer applications in this proceeding. The agreements provide that Michigan Wisconsin may take delivery of the prepaid gas at any time during the term of its contracts with the producers; however, takes may be charged against the prepayments only to the extent that they are in excess of the average daily contract quantities which Michigan Wisconsin is required to purchase under the contracts, and provided there are no outstanding deficiencies to be made up by reason of prior takes less than the contract quantities. The supplemental agreements further provide, with respect to the make-up of prepaid gas, for the daily delivery, upon request by Michigan Wisconsin, of volumes in excess of 125 percent of the average daily contract quantities, to the extent that the producers' equipment, prudent operations and State Conservation Commission regulations permit. The producers, however, are not required to deliver in excess of 125 percent of the average daily contract quantities except for the purpose of making up the prepaid gas.

The Woodward area of northwest Oklahoma lies within the counties of Woodward, Woods, Major, Dewey, and Alfalfa, and is just southeast of the Laverne field in Harper and Beaver Counties where Michigan Wisconsin is presently buying gas under Commission certificates at 17 cents per Mcf plus Btu adjustment. Woodward County along with Harper, Beaver, Ellis, Texas and Cimarron Counties comprise the Panhandle Area set forth in the Commission's Statement of General Policy No. 61–1, and for which the initial service rate level is 17 cents per Mcf. Woods, Major, Dewey, and Alfalfa Counties are in an area described for purposes of the Policy Statement as "Other," and which includes all of the remaining counties in Oklahoma except those parts of Grady and Stephens within the Knox field.[3] The initial service rate level for "Other" Oklahoma is 15 cents per Mcf.

The Issues.

The controversy in this proceeding centers on five basic questions:

(1) Is the initial contract price of 19.5 cents per Mcf required by the public convenience and necessity? If not, what price is so required?

(2) Should the initial price be uniform throughout the Woodward area, or should the initial price reflect the different levels established in the Commission's Statement of General Policy for the Panhandle and "Other" Oklahoma Areas?

(3) Is the provision for prepayment in the public interest and required by the public convenience and necessity?

(4) Is the Btu adjustment provision required by the public convenience and necessity as part of the initial price?

(5) Should the initial price be for undehydrated or for dehydrated gas?

The Examiner's Decision.

On July 14, 1961, the presiding examiner issued an initial decision granting certificates to the applicants herein subject to certain conditions. These conditions apply to the producer certificates and require: (a) The filing of an initial price of 17 cents per Mcf plus tax reimbursement; (b) the elimination of the prepayment provisions, or the modification thereof so that prepayments shall be credited against the first deliveries made. The producer certificates so issued would authorize the Btu adjustment to the base price as set forth in the producer contracts, and would establish the 17-cent base price as a uniform initial price for undehydrated gas throughout the Woodward area.

Exceptions to Examiner's Decision.

Exceptions to the examiner's decision have been filed by all of the producers except Skelly Oil Company and Wilcox Oil Company, and also by the Commis-

[3] The Knox field is set forth as a separate area known as the Carter-Knox area, with an initial price level of 16.8 cents per Mcf.

sion's staff. The producers' exceptions are directed to the imposition of the conditions on the initial price and the prepayment provisions. Staff excepts to the examiner's failure to follow the area levels set by the Statement of General Policy under which the 17-cent base price would apply only to Woodward County and 15 cents Mcf would be the proper initial price for gas from Woods, Major, Dewey, and Alfalfa Counties. Staff also excepts to the examiner's failure to require elimination of the Btu adjustment provision, and to his failure to specify that the initial price be for gas dehydrated in accordance with the standards for pipeline quality gas proposed in Docket No. R-200.

The Producer Certificates

Initial Price and Areas.

The questions here presented with respect to the initial price to be charged for gas from the Woodward area, are similar to those considered by the Commission in *Panhandle Eastern Pipe Line Co., et al.*, Docket Nos. CP60-103, *et al.* (Opinion No. 350, issued January 15, 1962). The producer applicants in the *Panhandle* case proposed wellhead sales of gas from these same Woodward area counties, and in some instances from the same fields. There, as in the instant case, the applicants argued for a uniform initial price for gas throughout the production area regardless of the fact that part of the gas was to be produced in the Panhandle area and part in the "Other" Oklahoma area, as those areas are delineated in the Policy Statement. And like the applicants in this proceeding, the producers there attempted to justify their initial contract price by comparing the proposed sales to presently certificated Laverne field sales in the Panhandle area, in light of evidence intended to show the geographical, geological, marketing and operating considerations governing the sales. The only essential difference between the present case and the *Panhandle* case is that the applicants here propose an initial price of 19.5 cents per Mcf as compared to the 17-cent price proposed in *Panhandle*.[4]

In support of their proposed 19.5-cent initial contract price, the producers presented evidence to show that the costs of production are higher in the Woodward area than in the Laverne area, where the Commission has already certificated wellhead sales at 17 cents per Mcf. They would show that the producing formations are deeper in the Woodward area; that the producing sands are scattered and lenticular and do not lend themselves to multiple completions; and that the general trend of costs is continually upward.[5] Although the examiner was persuaded by the producers' showing that the costs of production are higher in the Woodward area, he was nevertheless unable to determine any logical relationship between such evidence and the particular initial price proposed by the producers. In these circumstances the examiner concluded that the initial price should be no higher than the 17-cent ceiling price for the Panhandle area set forth in the Policy Statement. The examiner, however, would apply the 17-cent price uniformly to all of the proposed sales, whether in the Panhandle area or the "Other" Oklahoma area, finding, as did the examiner in the *Panhandle* case, that the Oklahoma Panhandle and the Woodward area are a single pricing area from a geological and marketing point of view, and that Woods, Major, Dewey, and Alfalfa Counties should be treated as part of the Panhandle area for the purpose of determining the proper initial price in this proceeding.

[4] Five of the producers here proposing sales at 19.5 cents share common wells with producers who proposed to sell their interest to Panhandle at 17 cents in the *Panhandle* case.

[5] 19.5 cents is the second step in the periodic price escalations provided for in the Laverne field gas purchase contracts.

Our Opinion No. 350 in the *Panhandle* case is controlling with respect to our determination of the price and area questions in this proceeding. In that case we set forth the basic considerations which govern the disposition of these questions. We there said, in part:

> The Policy Statement, however, should not be construed as suggesting that changes in either area boundaries or prices will readily be made in individual proceeding. It would defeat our purpose of simplifying and clarifying producer regulation, if every individual proceeding were to become a forum for attacking the area standards and we were to begin varying those standards from case to case. Adjustments in the area price structure can best be made upon a general review of all relevant factors. At the least, it would take a very compelling showing to warrant any change on an *ad hoc* basis.

Although the parties have gone to great lengths to justify the proposed initial price on the basis of comparative cost evidence and evidence to show the geological, operating and marketing characteristics of the Woodward area in relation to the Laverne area,[6] this evidence is not of such compelling nature as to convince us that we should depart from the pricing pattern established in the Policy Statement by ordering either an adjustment in price or in area boundaries on the basis of the record in this individual certificate proceeding. The existing area ceilings in the Panhandle and "Other" Oklahoma areas are based upon and are reasonably related to prevailing prices for wellhead sales as heretofore certificated by this Commission. Until such time as the Woodward area has developed to the extent that an area hearing can be fruitfully utilized to determine area prices, or unless evidence of the necessity of an *ad hoc* adjustment more compelling than that contained in the present record is presented, we shall adhere to the ceiling levels set forth in the Policy Statement. We shall therefore condition the certificates herein issued at an initial wellhead price of 17 cents per Mcf for sales in the Panhandle area, and at 15 cents per Mcf for sales in the "Other" Oklahoma area. Inasmuch as the ceilings in these areas are prices which include tax reimbursement, if any, the prices so allowed shall include all taxes, and no additional amounts for tax reimbursement shall be allowed.

As noted in Opinion No. 350 in the *Panhandle* case, the Commission is presently making a general review of area boundaries. In view of the fact that the Woodward area, which straddles the existing boundry between the Panhandle and "Other" Oklahoma pricing areas, was for the most part undeveloped at the time the present boundary was established, it is possible that some adjustment in that boundary may be made as a result of this study. If and when this should occur, we shall permit the producers to substitute new rates consistent with their contracts reflecting any increase in the area levels applicable to the sales herein certificated which may result from such adjustment, and thereafter to collect these new rates prospectively in lieu of the initial rates herein required. This is consistent with our treatment of the producers similarly situated in the *Panhandle* case. Also consistent with Opinion No. 350, we shall make the 100 percent take-or-pay provisions proposed by the producers, and herein allowed as part of their certificates, subject to our ultimate disposition with respect to such provisions in the current rule-making proceeding in Docket No. R–190.

The Prepayments.

The examiner disallowed the prepayment provisions because in his opinion they create an element of uncertainty with respect to the cost of the Woodward area gas to Michigan Wisconsin's jurisdictional customers. He found that the

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[6] One producer introduced cost of service evidence. Quite aside from the general question of the weight to be given cost evidence in individual producer certificate proceedings, it is apparent that the costs of one of twelve producers cannot be accepted as representative.

practical effect of the prepayments is to enhance the initial price of the gas; and although the impact may be small if the prepaid gas is taken as quickly as anticipated by Michigan Wisconsin, nevertheless the public interest requires that the Commission consider the potential effect of the prepayments in the "worst possible eventuality." Such an eventuality here would be that the prepaid gas would not be taken at all, or, if taken, might be taken so near to the end of the contract period that the price would be clearly exorbitant. The examiner therefore concluded that the prepayment provisions should be eliminated, or modified so as to require that the prepayments be credited against the first deliveries of gas under the various contracts.

In our opinion, the proposed prepayment provisions do not involve such a risk of exorbitant costs as to require us to disallow them. The evidence in this case shows the prepayments to be an essential part of the arrangements negotiated by Michigan Wisconsin and the producers to provide Michigan Wisconsin with an increasing gas supply to be integrated with its existing supplies in meeting the problem of the Phillips drop-off. We think that these arrangements represent a reasonable solution to Michigan Wisconsin's need for a large and flexible new supply; that such increased costs to jurisdictional customers as may reasonably be expected to result from the payments in advance of deliveries will not be excessive; and that the benefits to all concerned, including Michigan Wisconsin's jurisdictional customers, justify allowance of the prepayments.[7]

The prepayments in the amount of $4,014,928.17 apparently were made not only in consideration of the producers' agreement to hold the prepaid gas for later delivery as needed by Michigan Wisconsin, but also in consideration of the great flexibility allowed to Michigan Wisconsin in taking its contract quantities, especially in the early years of the contracts, and the dedication of extensive undeveloped and potentially productive acreage. They are thus basic to those features of the proposed sales which will enable Michigan Wisconsin to integrate its Woodward area supplies with the depletion of its deliveries from Phillips.

If allowed by us in this proceeding, the prepayments presumably would be included in Michigan Wisconsin's rate base as working capital for the purpose of determining Michigan Wisconsin's rates.[8] As part of the rate base, the prepayments would earn whatever rate of return Michigan Wisconsin is allowed in fixing its rates, and would so result in an additional cost to its jurisdictional customers. The extent of this additional cost would be determined by the rapidity with which Michigan Wisconsin can make up the prepaid gas, since the amount of the prepayments in the rate base would be reduced as the prepaid gas is actually taken by Michigan Wisconsin.

The prepaid gas to be made up by Michigan Wisconsin amounts to some 20,000,000 Mcf, or about two years of takes at the initial contract quantities. As noted above, Michigan Wisconsin can only make up the prepaid gas after taking currently required contract quantities and making up any prior con-

[7] The Commission allowed prepayments of a somewhat different nature in *El Paso Natural Gas Co.*, 22 FPC 260, 270.

[8] Michigan Wisconsin's rates for the future are now in the process of being determined in Docket No. RP60–9, a rate proceeding under Section 4 of the Act. Although the Commission has not yet rendered a decision in this case, it has approved in substance a stipulation which would include $3,656,615 in Michigan Wisconsin's rate base as working capital, subject to refund should the prepayments be disallowed in Docket No. CP61–102, *et al.* The amount so included represents the prepayments actually made during the 1960 test year. A part of the prepayment, amounting to $358,312, was made after the close of the test year. Michigan Wisconsin's total rate base, as stipulated to in this proceeding, is $214,824,344. The prepayments included as working capital would therefore constitute less than 2 percent of the total rate base.

tract deficiences resulting from deferrals in earlier years. Michigan Wisconsin may take up to 125 percent of the average daily contract quantities for the purpose of making up any contract deficiencies, and may take as much in excess of 125 percent of such quantities as is consistent with prudent operation of the wells for the purpose of making up the prepaid gas.

The record shows that Michigan Wisconsin plans to start taking 25,000 Mcf per day, and to take this amount daily for the first two years prior to the Phillips drop-off. These takes are about 75 percent of the average daily contract quantities based on presently proven reserves. Thereafter, Michigan Wisconsin proposes to make up the deficiencies so incurred by taking 125 percent of the contract quantities. If the additional reserves develop rapidly, the takes in the first years may drop to 25 percent, as contemplated by the contracts; but at the same time Michigan Wisconsin's ability to make up the deficiencies would increase because the make-up would be based on takes of 125 percent of the increasing contract quantities in subsequent years. Thus it appears from the record that Michigan Wisconsin should be able to make up any early-year deficiences within two years after the commencement of the drop-off.

Once these early-year deficiencies are made up, Michigan Wisconsin may begin to take the prepaid gas to the extent that prudent operation of the wells will permit. The record shows that if the wells are operated at maximum reasonable output, Michigan Wisconsin can make up the prepaid gas by the end of 1968, the eighth year following the prepayments, and six years after the commencement of the Phillips drop-off. This assumes that no additional reserves are proved. If additional reserves are proved, and it may be reasonably expected that they will be, Michigan Wisconsin can, and no doubt will, accelerate its takes of prepaid gas in order to meet the drop-off. Thus, in all probability, Michigan Wisconsin will have completed the make-up of both its early-year deficiencies and the prepaid gas within a period of eight years from the time of the prepayments.[9] Although there is a possibility, as staff contends, and as the examiner found, that the Woodward area wells might not produce as anticipated and that Michigan Wisconsin might not be able to take the prepaid gas as rapidly as the experts who have testified herein would expect, if at all, it is admitted that this is to view the operation "in extremis"; and in our judgment the possibility of Michigan Wisconsin not being able to take the prepaid gas at all, or only in the latter years of the contracts, is not of sufficient likelihood to warrant the conclusion that the public interest requires us to decide the propriety of the prepayment provisions on the basis of such an unrealistic assumption.

Assuming a total of some 20,000,000 Mcf of prepaid gas at 19.5 cents per Mcf, the proposed initial price under the contracts, and further assuming that the amount so paid for each Mcf of prepaid gas earns 6¼ percent as part of Michigan Wisconsin's rate base,[10] the added cost of prepayments to gas consumers, over the eight years which Michigan Wisconsin will require to take the prepaid gas if no additional reserves are proven, will be $1,341,980. Staff

[9] The Phillips' drop-off is estimated to be 45,300 Mcf per day in 1964, 82,600 Mcf in 1965, and 172,500 Mcf in 1966. With this drop-off providing continually increasing capacity in its system so as to enable it to take increasing larger amounts of gas from the Woodward area, and with its potential markets and its availble storage, Michigan Wisconsin should be able to absorb all of the gas which will become available to it under its contracts as the Woodward area reserves are developed.

[10] Both the staff and Michigan Wisconsin briefs assume a 6¼ percent return and the 19.5-cent proposed price in computing the cost of prepayments in Michigan Wisconsin's rate base.

contends that this cost should be assigned only to the 20,000,000 Mcf of prepaid gas. On this basis, the additional cost of the prepaid gas would be 6.7 cents per Mcf. However, the prepayments were made not merely in consideration of the deferred delivery of the 20,000,000 Mcf, but for all of the reserves, both proven and potential, to be delivered to Michigan Wisconsin under the producer contracts. Thus, the $1,341,980 should properly be rolled in with the cost of all gas delivered to Michigan Wisconsin under the contracts, and spread over the total volumes so delivered. Spread over the 238,000,000 Mcf of reserves proven at the time these applications were filed and the prepayments were made, the additional cost would be .564 cent per Mcf. Should the total proven reserves double, triple, or quadruple, as hoped by Michigan Wisconsin, this cost would be further reduced as follows: .268 cent per Mcf for 500,000,000 Mcf; .179 cent per Mcf for 750,000,000 Mcf; and .134 cent per Mcf for 1,000,000,000 Mcf. We cannot, of course, anticipate at what rate, or to what extent, the Woodward area reserves will develop. However, we do not think it unreasonable to expect that they will develop, and that the additional cost will in fact be something less than .5 cent per Mcf. In addition to this cost, which represents return on the prepayments included as working capital in Michigan Wisconsin's rate base, there will be an essentially like amount to be paid by Michigan Wisconsin's ratepayers to cover additional income taxes which must be included in Michigan Wisconsin's cost-of-service because of the added return on the prepayments.

In view of the proceedings in Docket No. RP60-9, and the conditions here imposed on the proposed initial prices, these cost figures are only rough approximations. Nevertheless, they are sufficient to show that the additional cost to Michigan Wisconsin's jurisdictional customers which may be expected by reason of the prepayments is not unreasonable in light of the benefits to be derived from Michigan Wisconsin's acquisition of these reserves with the right to take the gas as it needs it to meet the Phillips drop-off.[11] The producers' agreement to defer deliveries so as to enable Michigan Wisconsin to integrate its takes with the drop-off of its Phillips supplies is, in our judgment, a "service or forbearance" in connection with the sale of this gas which justifies consideration of the benefits thereof to Michigan Wisconsin and to Michigan Wisconsin's customers in determining whether the increase in the initial prices which would result from allowance of the prepayment provisions is required in the public interest;[12] and in our opinion these benefits warrant the conclusion that both the prepayment provisions and the additional costs to be associated therewith are in the public interest and are required by the public convenience and necessity.[13]

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[11] If the Phillips drop-off were not replaced with this Woodward area gas, the additional cost to Michigan Wisconsin's customers in 1964, assuming the 19.5-cent proposed initial price, would be 0.61 cents per Mcf. With annual estimated sales of 254,467,000 Mcf for 1964, the total cost to consumers would be $1,552,000. For 1965 the extra cost per Mcf would be 2.32 cents, or a total cost of $5,482,000 based on annual sales of 236,312,000 Mcf. These costs, which reflect the decrease in Michigan Wisconsin's gas deliveries which would result from the Phillips' drop-off, would be even greater if the computations were based on the conditioned prices required by this Opinion.

[12] See Opinion No. 350, page 13.

[13] Inasmuch as we are conditioning the certificates herein issued to require the filing of initial prices of 15 or 17 cents, depending upon the area of the sales, we shall require the substitution of such prices in the supplemental agreements providing for the prepayments, and shall require the producers to credit against their first deliveries to Michigan Wisconsin the difference between the prepayments actually made and those that properly should be made at the conditioned prices.

The Btu Adjustment.

In this proceeding, as in the *Panhandle* case, we are faced with the problem of passing on a proposed Btu adjustment, which is an integral part of the parties' contract arrangements, prior to completion of the pending rule-making proceeding in Docket No. R–200, in which it is our intention to determine, as a matter of general policy, whether such adjustments should be allowed in producer contracts, or, if allowed, the conditions to govern their operation. In the absence of basic policy guidelines with respect to Btu adjustments, to be established in Docket No. R–200, our determination of the Btu question in this case must necessarily be limited in scope, and should not be construed either as a precedent to be relied upon or followed in subsequent proceedings, or as a prejudgment of the issue presented in the rule-making proceeding.

Our primary concern with the Btu adjustment is its potential impact upon the pipeline company's jurisdictional gas service. If there is no adverse impact upon Michigan Wisconsin's jurisdictional customers by reason of the operation of the proposed adjustment, and there are benefits to be realized therefrom by the producers, the pipeline, or gas consumers, then, in our opinion, the proposed adjustment may be allowed; subject, however, to such conditions as may be necessary to fully protect the public interest, including a condition making the allowance of the adjustment in this case contingent upon and subject to the general policy requirements to be set forth in Docket No. R–200.

The base initial price in Michigan Wisconsin's contract with the producers is for gas with a heating value of 1,000 Btu's per cubic foot. The Btu adjustment provisions in the contracts would increase the base price by 1/100 cent per Mcf for each additional Btu over 1,000, with a maximum adjustment based on a heating value of 1,200 Btu's per cubic foot. No adjustment is provided for gas containing less than 1,000 Btu's.[14]

It is expected that all of the gas in this case will be gathered to a central point and will be processed for the removal of the heavier hydrocarbons by either the producers or by Michigan Wisconsin prior to transmission through Michigan Wisconsin's new lateral. Thus the Woodward area gas, which is estimated to run on a composite stream close to 1,100 Btu's, will be stripped to close to 1,000 Btu's before entering Michigan Wisconsin's mainline system. In these circumstances, it is not anticipated that Michigan Wisconsin will encounter any operating difficulties by reason of its purchase of high Btu gas at the wellhead; and to the extent that the processed gas is not stripped below 1,000 Btu's per cubic foot when it enters Michigan Wisconsin's new lateral, it can be mixed with Michigan Wisconsin's low Btu Phillips' gas so as to enhance to some degree the average heating value of Michigan Wisconsin's mainline gas stream.[15] Any such increase in the heating value of Michigan Wisconsin's gas would be within a range which normally can feasibly be utilized by most gas consumers. Thus, there seems to be no serious problem with respect to the transmission and use of this proposed gas supply in Michigan Wisconsin's system or with respect to the cost of transmission associated therewith. There remains to be considered, however, in determining whether the Btu adjustment should be allowed, the effect of the operation of the adjustment provisions on the pipeline's purchased gas cost. If the cost of purchased gas to be passed on to jurisdictional cus-

[14] The contracts provide that the gas shall have a total heating value per cubic foot of not less than 1,000 Btu's and not more than 1,200 Btu's.

[15] Michigan Wisconsin's Form No. 2 filed with the Commission for the year 1960 shows a weighted average Btu content of 995 for gas delivered through its main line transmission system from the southwest. Michigan Wisconsin's gas is not processed for the removal of liquids after it enters the mainline system.

tomers is not increased out of proportion to the benefits to be derived from the purchase of the additional Btu's the adjustment may properly be allowed subject to such conditions as may be required to fully safeguard the consuming public.

Michigan Wisconsin has entered into precedent processing agreements with the producers whereby the latter are given an option to construct and operate, either alone or in cooperation with others, a gas products recovery plant on Michigan Wisconsin's lateral for the purpose of processing the gas. If any producer exercises this option, then all of the gas purchased by Michigan Wisconsin in the Woodward area will be gathered and delivered by Michigan Wisconsin to the producer's plant for processing, whether or not other producers join in the processing arrangements. Under the agreements, the producers participating will reimburse Michigan Wisconsin for shrinkage and fuel used in processing, as well as for the loss of Btu's down to 1,000 on a basis of 1/100 cent per Mcf per Btu. Thus, to the extent that the gas is not stripped below 1,000 Btu's, Michigan Wisconsin will recover essentially what it pays for the Btu's at the wellhead, and there will be no adverse impact on Michigan Wisconsin's jurisdictional rates by reason of the Btu adjustment provisions in the producer contracts.

Should none of the producers exercise the option to process the gas—an unlikely occurrence in view of testimony by representatives of both the producers and Michigan Wisconsin as to the desirability and profitability of the stripping operation—Michigan Wisconsin will process the gas itself. However, even if this should occur, the Btu adjustment provisions in the purchase contracts would not operate to the disadvantage of Michigan Wisconsin's jurisdictional customers, since in fixing Michigan Wisconsin's rates the Commission would either offset the profits from the sale of the liquids against the increased cost of gas, or would allocate the additional cost of the Btu's removed in processing to the sale of the liquids and not to the jurisdictional resale of the gas. It should further be noted in this connection, that the cost of the additional Btu's to Michigan Wisconsin under the limited type of Btu adjustment provided in these contracts will be considerably less than would be the case under a full percentage type of adjustment such as that recently allowed by us in the *Panhandle* case, referred to above. Thus, assuming a base price of 17 cents per Mcf for 1,000-Btu gas, which is a price of .017 cents per 1,000 Btu's, a full percentage type of adjustment would result in an additional cost of .017 cent per 1,000 for the excess Btu's. Under the limited adjustment here provided, the excess Btu's will cost Michigan Wisconsin only .010 cent per 1,000.

Under the terms of the purchase contracts, the producers may not process their gas for the removal of liquids at the wellhead. They must, if they wish to process, exercise the option under the precedent processing agreements to undertake, individually or in cooperation with others, the construction and operation of a central plant through which all of the gas gathered in the Woodward area will be processed. The purpose of this provision is to insure delivery of a sufficiently rich stream of gas to the central plant to make the operation profitable. If there were no Btu adjustment provisions in the purchase contracts, those producers who are either unwilling or unable to enter into a centralized processing operation would be unable to realize any revenue for the additional heating volume of their gas, as represented by Btu's per cubic foot over 1,000 sold to Michigan Wisconsin at the wellhead. Thus, even though the net effect of the operation of the Btu adjustment may be a "wash" so far as Michigan Wisconsin is concerned, the Btu adjustment will nevertheless provide partial compensation for those producers who do not join in the processing operation.

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In our judgment the Btu adjustment provisions will not adversely affect Michigan Wisconsin's jurisdictional gas customers, and as applied under the circumstances of this case may be found to meet the test of public convenience and necessity. We shall therefore allow the adjustment, subject however to the following conditions required in the public interest. First, the adjustment, as herein allowed, shall be subject to our determination with respect to such adjustments as a matter of general policy in the current rule-making proceeding in Docket No. R-200; and we reserve continuing jurisdiction to require modification of the adjustment provisions in the purchase contracts and processing agreements consistent with the policy so determined and the requirements of the public convenience and necessity in the circumstances of these sales.[16] However, no such modification of the terms and conditions of the purchase contracts or the processing agreements shall be made which would permit a Btu price adjustment more favorable to the producers than the limited price adjustment for Btu's over 1,000 per cubic foot now provided in the producers' contracts with Michigan Wisconsin and herein certificated. Allowance of the adjustment herein shall be further conditioned upon inclusion in the rate schedules to be filed by the producers of a full percentage downward adjustment in price for gas having less than 1,000 Btu's per cubic foot, and upon modification of the precedent processing agreements to require reimbursement by the producers to Michigan Wisconsin on the basis of a full percentage adjustment for the removal of Btu's below 1,000 in processing the gas.

The purchase contracts presently contain no provision at all for a downward adjustment in price for gas having less than 1000 Btu's per cubic foot. Similarly, the precedent processing agreements contain no provisions for reimbursement to Michigan Wisconsin for Btu's below 1,000 removed by the producers in stripping the gas, although they provide that the producers may strip the gas to 950 Btu's before redelivering it to Michigan Wisconsin at the tailgate of the processing plant. In the absence of such provisions, gas consumers would be required to pay for Btu's not received if Michigan Wisconsin were to take delivery of gas of less than 1000 Btu's at either the wellhead or the tailgate of the plant.[17] To protect the consumer against such an occurrence, the full percentage type of adjustment referred to is required; since only through the operation of this kind of adjustment will the price of the gas be adjusted on the basis of the price which Michigan Wisconsin is required to pay for the Btu's at the wellhead.

Under the full percentage type of adjustment, the reduction in the wellhead price for gas of less than 1,000 Btu's, and the reimbursement to Michigan Wisconsin for Btu's below 1,000 removed by the producers in processing the gas, are computed as that proportion of the base price for 1000 Btu gas which the number of Btu's below 1,000 bears to 1,000. Thus, if the base price is 17 cents per Mcf, and the gas is delivered to Michigan Wisconsin after processing at 950 Btu's, the reimbursement for the 50-Btu reduction below 1,000 would be 50/1,000×17 cents per Mcf, or .85 cents per Mcf. This is a price for the Btu's of .017 cents per 1,000, which is the price paid by Michigan Wisconsin for the Btu's at the wellhead.

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[16] Such modification as may be required in accordance with this condition and the policies to be set forth in Docket No. R-200 shall be prospective only.

[17] Although Michigan Wisconsin is not required to take delivery at the wellhead of gas with a heating value of less than 1,000 Btu's, it is possible that it may do so, and provision should be made for the protection of the gas consumers should this occur.

Dehydration.

Staff urges that the initial prices herein certificated should be for gas which has been dehydrated in accordance with the standard for pipeline quality gas proposed in Docket No. R–200. Under this standard, the producers would be required to deliver the gas to Michigan Wisconsin with a water content of not more than 7 lbs. per million cubic feet. Statement of General Policy No. 61–1 indicates that the price standards therein set forth apply to "pipeline quality gas as that term is generally understood in each area." There is nothing in the record in this case to show that the proposed sales are not of pipeline quality gas as that term is generally understood in these pricing areas. The gas is from the same fields, and in some instances from the same wells, as that which we authorized to be sold to Panhandle at the ceiling levels in the *Panhandle* case referred to before.[18] Furthermore, as heretofore, this gas will in all probability be processed by the producers in accordance with the precedent processing agreements; and under these agreements the producers are required to deliver the gas to Michigan Wisconsin at the tailgate of the processing plant with a water content of not more than 5 lbs. per million cubic feet.

The Pipeline Certificate

Michigan Wisconsin's need for additional gas supplies to offset the dropoff in deliveries from Phillips is clearly established. The Phillips gas presently represents nearly two-thirds of Michigan Wisconsin's total supply to the southwest, and Michigan Wisconsin must replace this southwestern supply with new gas from the same general area if it is to maintain service through its existing mainline facilities on a high load factor basis. The record shows that the Woodward area represents the only substantial proved and uncommitted reserves located within reasonable proximity to Michigan Wisconsin's mainline. There does not appear to be any question with respect to the desirability of the proposed gas supply, or with respect to the cost, the economic or engineering feasibility, or the financing of Michigan Wisconsin's proposed facilities for the transportation of the gas.[19] Accordingly, we shall certificate the construction and operation of the facilities proposed by Michigan Wisconsin in its application; subject, however, to acceptance by the producer applicants of the certificates herein issued to them for the sale of the Woodward area gas to Michigan Wisconsin.

The Commission further finds:

(1) Michigan Wisconsin is a "natural gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission.

(2) Michigan Wisconsin's proposed facilities hereinabove referred to, and more fully described in the application, will be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and such facilities, together with the construction and operation thereof, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

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[18] Allowance of the ceiling prices for sales at the wellhead or at the outlet of separators near the wellhead in this case and the *Panhandle* case, does not constitute a determination by us of the standard of pipeline quality to be applied to gas sold in these areas. This determination will be made in Docket No. R–200.

[19] Michigan Wisconsin's proposed facilities consist generally of some 62 miles of 20-inch line, 35 miles of 16-inch line, 69 miles of smaller diameter line. The estimated cost of these facilities is approximately $6,796,000.

(3) Each of the independent producers named above as parties to this proceeding is or upon initiation of the proposed sales to Michigan Wisconsin will be engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission, and is or will be a "natural-gas company" within the meaning of the Natural Gas Act.

(4) The sales of natural gas proposed by each of the producer applicants, as more fully described in their applications, are subject to the jurisdiction of the Commission, and such sales, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) Subject to the requirements of our order herein and the conditions of the certificates herein issued, Michigan Wisconsin and the producer applicants are able and willing to properly do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(6) The construction and operation of the facilities proposed by Michigan Wisconsin, and the sales proposed by each of the producer applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity, and certificates should be issued to each of them as hereinafter ordered and conditioned.

(7) The conditions attached to the certificates of public convenience and necessity herein issued are required by the public convenience and necessity.

The Commission orders:

(A) Certificates of public convenience and necessity are hereby issued, upon the conditions hereinafter set forth, to Michigan Wisconsin Pipe Line Company for the construction and operation of the facilities proposed, as more fully described above and in its application, and to each of the above-named independent producers for the sale of natural gas in interstate commerce for resale as proposed, and for the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, as more fully described above and in their applications.

(B) The certificate herein issued to Michigan Wisconsin and the rights granted thereunder are conditioned upon Michigan Wisconsin's compliance with all applicable Commission Regulations under the Natural Gas Act, and particularly the general terms and conditions set forth in paragraphs (a), (b), (c), and (e) of Section 157.20 of such Regulations. The time within which Michigan Wisconsin's facilities shall be constructed and placed in actual operation, as provided by paragraph (b) of Section 157.20, is hereby fixed at six months from the date of issuance of this order.

(C) The certificates herein issued to the producer applicants are granted upon the express condition that each of said producers shall file a rate schedule with the Commission within 30 days from the date of issuance of this order providing for an initial wellhead price, replacing the initial contract price as proposed, not in excess of 15 cents per Mcf, at 14.65 psia, including tax reimbursement, for gas sold in Woods, Dewey, Major and Alfalfa Counties, and not in excess of 17 cents per Mcf, at 14.65 psia, including tax reimbursement, for gas sold in Woodward County. The initial price, as so conditioned, shall be subject to upward adjustment for gas containing more than 1000 Btu's per cubic foot as proposed; provided, however, as a further condition of the issuance of the certificates herein, that the rate schedules to be filed by the producer applicants shall also make pro-

vision for a full percentage downward adjustment in price for gas containing less than 1000 Btu's per cubic foot. The precedent processing agreements shall be similarly modified to provide reimbursement to Michigan Wisconsin on the same basis for Btu's below 1000 removed by the producers in processing the gas. Except as provided by this order, said rate schedules shall in all respects conform to the producers' applications.

(D) In the event the Commission, by amendment of Policy Statement No. 61–1, adjusts the boundary between the Panhandle area and the "Other" Oklahoma area so as to increase the initial wellhead price level for new gas in the area of the sales herein certificated, the producer applicants accepting the certificates herein issued may thereupon substitute new rates consistent with their contracts reflecting the amount of such increase, and thereafter collect these new rates prospectively in lieu of the initial rates herein required.

(E) The certificates herein issued to the producer applicants are granted upon the express condition that the allowance of the take-or-pay provisions and the upward Btu price adjustment provisions in their contracts with Michigan Wisconsin is subject to our ultimate disposition with respect to such provisions in the rule-making proceedings in Docket Nos. R–199 and R–200, respectively; provided, however, that no modification of the terms and conditions of the purchase contracts or the processing agreements with respect to the operation of the Btu adjustment shall be made which would permit a Btu price adjustment more favorable to the producers than the limited price adjustment for Btu's over 1,000 per cubic feet now provided in the producers' contracts with Michigan Wisconsin and herein certificated. Upon the establishment by amendment to the Statement of General Policy No. 61–1, or by regulation, of general policies governing such provisions in producer contracts, the producers accepting the certificates herein issued shall file within 30 days amended rate schedules in conformity therewith and with this paragraph (E). The producers shall not be required to file take-or-pay provisions for less than 80 percent of the annual contract quantities. Any changes or modifications to be made in accordance with this paragraph (E) shall be prospective only.

(F) The certificates herein issued to those producer applicants who have entered into supplemental agreements with Michigan Wisconsin for prepayments of gas are granted upon the express condition that the amount of said prepayments be recalculated on the basis of the reduced initial prices required by paragraph (C) above; and to the extent that the prepayments heretofore made exceed the amount of the prepayments as so recalculated, the producers shall credit the prepayments made against the first deliveries of gas to Michigan Wisconsin under the basic contracts. The producers shall submit to the Commission within 30 days from the date of issuance of this order the recalculation of the prepayments herein required, together with a statement of the excess of prepayments to be credited against the purchase price of gas first sold to Michigan Wisconsin pursuant to the contracts.

(G) The certificates herein issued to the producer applicants shall be accepted in writing and under oath within 30 days from the date of the issuance of this order; and the facilities authorized by said certificates shall be constructed and placed in actual operation within six months from the date of the issuance of this order.

(H) The certificates herein issued to the producer applicants are not transferable and shall be effective only so long as each of said applicants continues the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act, and the applicable rules, regulations and orders of the Commission.

(I) The grant of the certificates herein shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act, or of Part 154 of the Regulations thereunder. Such grant is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicants. Further, the action in this proceeding shall not foreclose nor prejudice any further proceedings or objection relating to the operation of any price or related provision in the gas purchase contracts herein involved.

(J) The certificate herein issued to Michigan Wisconsin shall not become effective until acceptance by the producer applicants of the certificates herein issued to them.

(K) Except as herein granted the exceptions to the examiner's decision are hereby denied.

DECISION

UPON APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY UNDER THE NATURAL GAS ACT

(Issued July 14, 1961)

COSTELLO, *Presiding Examiner:* This is a certificate proceeding which was initiated by the applications of Michigan Wisconsin Pipe Line Company and twelve independent producers of natural gas.[1] Michigan Wisconsin and the producers are seeking jointly and severally to obtain Commission approval of a transaction which would provide Michigan Wisconsin with a large amount of natural gas for general use on its system. Before discussing the matter in somewhat greater detail, it might be mentioned that there are two features of this proposed transaction which will draw the greatest attention by the Commission. These features generally relate to the proposed initial price to be paid by Michigan Wisconsin for the gas in question, and the other feature is related to a prepayment plan under which the pipeline company would pay in advance for natural gas to be taken in subsequent years. Other than for these two features and a question with respect to the acceptability of a Btu adjustment provision in the contract, there are no significant problems which merit attention.[2]

This matter involves a relatively short record which was accumulated over some eight hearing sessions. There are no participants other than for the pipeline and producer applicants and the Commission's Staff. Absent from participation in the hearing phase of the proceeding are any of Michigan Wisconsin's numer-

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[1] These producers are as follows:

Pan American Petroleum Corporation, Shell Oil Company, Sinclair Oil and Gas Company, Wilcox Oil Company, Atlantic Refining Company, Kerr-McGee Oil Industries, Inc., Skelly Oil Company, Woodson Oil Company, Amerada Petroleum Corporation, Sun Oil Company (Mid-Continent Division), J. M. Huber Corporation, and Sunray Mid-Continental Oil Company.

It might be remarked that the project herein involved 16 producer contracts of which only 12 are embraced by this proceeding.

[2] There was a question raised by the Staff with respect to the dehydration of the gas. Several producers scoffed, some indicated puzzlement, others and Michigan Wisconsin did not discuss the matter. It appears to have only minor significance. Pipeline quality gas, in the area in question, is "sweet gas, undehydrated, delivered at natural well pressure at the wellhead or the outlet of the separator located nearby the well, of a Btu content in excess of at least 950 Btu's per cubic foot." Under this definition, provided by Shell's Mr. Golush, the producers have contracted to sell Michigan Wisconsin pipeline quality gas. Michigan Wisconsin must dehydrate the gas.

ous customers and the state regulatory commissions from the states in which Michigan Wisconsin provides natural gas service. The only opposition of record to the proposals of these applicants stems from the Staff of the Commission, which has taken the position that the proposals are not acceptable in their present form.

It might be noted at this point that the questions and issues have been very carefully and thoroughly briefed by all of the major participants. The briefs and arguments submitted contain careful and skillful analyses of the record, the issues, and the precedents which may have a bearing upon the Commission's consideration of this matter.

The facts are relatively simple. Michigan Wisconsin desires to construct and to operate a supply lateral and gathering facilities which will enable it to receive and transport natural gas from the Woodward area of northwest Oklahoma to its existing main line.[3] These facilities of Michigan Wisconsin would consist generally of some 62 miles of 20-inch line, 35 miles of 16-inch line, as well as some smaller diameter line aggregating approximately 69 miles. The cost of these facilities is estimated at approximately $6,796,000.[4]

It should be noted for the benefit of those not well acquainted with Michigan Wisconsin Pipe Line Company and its history that this proposal does not relate to an expansion program of the pipeline but relates to an anticipated decline in gas supply from Michigan Wisconsin's principal supplier, Phillips Petroleum Company. The Michigan Wisconsin system was launched with Phillips gas, which was known to have a limited life. It was known at the time Michigan Wisconsin began its operations that the Phillips gas would have to be replaced within a foreseeable time. Michigan Wisconsin is obligated to purchase its first 343,000 Mcf of gas from Phillips so long as Phillips is able to maintain that deliverability. It is known, however, that Phillips cannot deliver the full 343,000 Mcf per day in 1963 and in later years. This situation, which is commonly referred to in the record and by the witnesses as the Phillips "drop-off," is the problem Michigan Wisconsin hopes to solve by the contracts it has entered with the producers in the Woodward area. It is believed that the drop-off by Phillips will result in a daily average delivery of less than 300,000 Mcf in 1964, and that by 1967 this amount will have been reduced to something less than 200,000 Mcf per day. In order to maintain its pipeline on a high-load factor basis, Michigan Wisconsin must procure additional gas from some source. It faces the alternative of purchasing or attempting to purchase smaller packages of gas to fit the drop-off as this drop-off occurs, or to contract for enough gas now to meet all of the anticipated drop-off whenever it might occur.

Because independent producers, as a general rule must insist that a purchaser take delivery of gas very near its time of purchase, and because the drop-off by Phillips will be gradual, Michigan Wisconsin cannot contract for and take delivery of any large amount of gas at any one time unless there is some way of disposing of the gas which is surplus to its immediate needs, until such time

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[3] This is an area described as consisting of approximately 30 townships located in Woodward, Woods, Major and Dewey Counties, Oklahoma, and situated immediately adjacent to and southeast of Laverne Field, Oklahoma.

The fields included in this area are the Northeast Cederdale Field of Major and Woodward Counties; the Northeast Selling Field of Major County; the Northwest Chester Field of Woodward County; the West Campbell Field of Major County and the Lenora Field of Dewey County, all in Oklahoma.

[4] The lateral line involved herein would run from Michigan Wisconsin's compressor Station #2 to the Cederdale Field in Woodward County, and would have a capacity to carry "upwards of 100 million cubic feet per day."

as its needs have expanded to the point where all of the gas may be fitted into its load pattern.[5]

There are probably a number of ways this problem may be solved. Michigan Wisconsin has chosen an arrangement whereby gas reserves in this large new field[6] have been contracted for with producers with fairly substantial prepayments being made to the producers in lieu of immediately taking the gas. Another solution, as indicated above, would be to wait until the needs for additional quantities of natural gas actually arise and, at, or just before that time, scout around for the needed quantities of gas. Another possible partial solution which has been advanced by the Staff and which has aroused considerable indignation by Michigan Wisconsin, would be the giving up of certain undeveloped Phillips gas by Michigan Wisconsin from the so-called Kathryn Field, which gas is to be made available to Michigan Wisconsin later.[7] Such foregoing of the taking of the Kathryn gas from Phillips, the Staff has urged, would provide more opportunity for Michigan Wisconsin to take greater quantities of gas under the present proposed arrangement at an earlier date. Another solution (and there may be several others which will not be advanced herein) would be for Michigan Wisconsin to make arrangements with some other pipeline company to share in the utilization of gas involved in these contracts, until Michigan Wisconsin finds it necessary to utilize the gas entirely for its own needs. There is no suggestion in the record that any attempt has ever been made by Michigan Wisconsin to find such other pipeline which might be able to cut down its own takes from existing sources, or to cut back on its own production, in order to utilize some of the Woodward area gas for a while.

None of the briefs of the applicants or the Staff has cited cases wherein this particular kind of arrangement has been proposed to the commission before in a certificate case, *i.e.*, a prepayment for gas.[8]

The other matter which calls for particular attention by the Commission in its disposition of these applications is the proposed 19.5 cents per Mcf price which is involved in all of these contracts. This price is one which does not stem from any prior or existing sale in the area (as this is a new field) and therefore the initial price proposed herein is one which must be carefully considered in the light of precedent, and with consideration of the effect such price may have upon the public interest and the regulatory processes of the Commission.[9] In general, the applicants have presented all of the evidence which they

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[5] In general, the contracts herein meet this problem by providing that Michigan Wisconsin's rate of take shall be one million cubic feet per day for each 7.3 billion cubic feet of agreed-upon reserves with a daily minimum of 75 percent and a daily maximum of 125 percent of that volume. In addition, during the first three years after deliveries commence, Michigan Wisconsin has the contract right to reduce its takes down to 25 percent of the average daily quantity with the right to take make-up gas over the life of the contracts. (One producer, Pan American, provides a minimum take of 40 percent and a make-up period of 10 years beyond the initial three years of delivery).

[6] 287,000 net acres with 238 billion cubic feet of proved reserves.

[7] The Kathryn sale is not yet covered by certificate. It is assigned Docket No. CI61–1237 and, of course, is not before this examiner, and may not be commented upon appropriately herein. The Kathryn gas is 13 cent gas.

[8] Subsidy-type prepayments have been considered an acceptable cost in at least one rate case.

[9] *cf* the *Humble Case*, G–13679, 24 FPC 191 at 193: "In view of the Supreme Court's emphasis in the *Catco* case on holding the line on gas prices, *particularly in new and undeveloped gas fields*, we consider that we should not lightly give our approval to these proposed new higher initial prices. One or a few higher prices in a new field inevitably exert pressure for increased prices for all other sales in the vicinity, even though all sales may not be identical as to conditions of production or delivery, thus forming the basis

believe would have a bearing upon this matter of the initial contract price. The Staff of the Commission believes the initial price to be excessive and recommends that a certificate, if granted by the Commission, should contain a condition which will reduce the price by two to four cents per Mcf, depending upon its source. All of these matters will be discussed in some detail in the following text.

Additional Factual Considerations

In 1957 Michigan Wisconsin applied for and obtained authority to construct lateral main line facilities to transport gas from the Laverne Field in northwestern Oklahoma. The Laverne Field has been developed by at least some of the same producers that are involved in this case, and is in the general vicinity. The Laverne contracts contain the key to the 19.5 cents for the Laverne gas under its contracts beginning in 1964. The Laverne gas started out at 17 cents per Mcf but will go to 19.5 cents per Mcf in 1963 under the periodic price increase provision in the Laverne contract. There are many statements in the record and important argument to the effect that the Laverne development and production costs are considerably lower than the Woodward costs would be, and that the 2.5 cents additional amount for the initial price for Woodward gas is more than justified by the particular geology involved, as well as cost trends since the Laverne Field was opened.

There is no question but that if Michigan Wisconsin could obtain approval of the instant proposal absent any price problem arising either from the stated initial price or from the price aspects of the prepayment proposal, the solution it proposes to its drop-off problem would be ideal. Michigan Wisconsin would obtain flexibility in its takes of gas and it would obtain the dedication of potentially productive acreage which is greater than that usually provided by other gas purchase contracts. By having the gas from the Woodward area available when the drop-offs from Phillips are experienced, Michigan Wisconsin would be able to maintain its pipeline at a high-load factor and would thereby obviate the cost of service impact which would surely result from operating the pipeline at its less than full capacity.

Michigan Wisconsin has no production of its own. It has been tied to Phillips since 1945 under an agreement which has obligated it to take its first 343,000 Mcf per day from Phillips so long as Phillips is able to deliver that volume. If Phillips is not able to deliver the full volume, Michigan Wisconsin is still obligated to purchase such lesser volume. In these circumstances, it may be observed that Michigan-Wisconsin has had little flexibility in being able to acquire any firm substitute gas supply until the shortages actually occur on the Michigan Wisconsin system. The Phillips deliveries represent nearly two-thirds of Michigan Wisconsin's total supply in the southwest, and this pipeline does not now have numerous supply lines and gathering systems into areas of potential production.

There is no question about the decline in production from the Hugoton Field within a very short time. As noted previously, Phillips will be required to develop the so-called Kathryn or sub-sea acreage in order to maintain the full deliveries of 343,000 Mcf per day in 1962.

The record in this matter shows that from five fields in the Woodward area Michigan Wisconsin will have access to recoverable reserves of 304,076,000 Mcf and that the proved recoverable reserves under contract amount to 238,000,000 Mcf.

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for general area price rises. The prevention of such results was a major objective of the *Catco* decision." (emphasis added)

The record also supports the proposition that the Woodward area of western Oklahoma represents the only substantial proved and uncommitted reserves which lie within reasonable proximity to Michigan Wisconsin's main line. It is argued that the only areas of present and potential production available to Michigan Wisconsin to meet the Phillips drop-off are the Woodward and adjacent areas.

There has been no question raised with respect to the cost or engineering feasibility of the proposed facilities. The Michigan Wisconsin engineering and operating personnel are experienced and skillful, and there is no question with respect to the ability of the proposed facilities to provide the transportation capacity required.

Michigan Wisconsin's proposed facilities will be financed by short-term bank loans and by internally-generated funds. Permanent financing will follow as a part of a subsequent over-all financing program. It is contended by Michigan Wisconsin and its witnesses that failure to replace the Phillips drop-off with this particular gas from the Woodward area would be detrimental to the customers of Michigan Wisconsin and would actually result in an increase of their cost of gas. If present pipeline deliveries are reduced, the cost of service for the remaining deliveries will be increased. Thus it would be the customers who would bear the brunt from an inability of Michigan Wisconsin to keep its line filled from the southwest to Station 10 in Illinois.

The only alternative suggested by Michigan Wisconsin would be for it to obtain additional gas from its other suppliers, namely Midwestern and American Louisiana. This purchase of gas from either of these two suppliers would be expensive and even if purchased would not improve the use or load factor on the lower end of the system.

It does not appear that there is any substantial issue with respect to the desirability of the gas which Michigan Wisconsin seeks to have authorized nor the economic feasibility of the proposal from the standpoint of Michigan Wisconsin. While the gas it would purchase from the producers involved in this matter is vastly more expensive than the Phillips gas which it will replace, Michigan Wisconsin has demonstrated that its failure to get gas for replacement even at this price would result in considerable detriment to its customers.

The Issues and Elements of Proof

As indicated heretofore, the issues in this matter stem almost entirely from the initial price proposed for the Woodward area gas. The issue stated in general terms is, of course, whether the public convenience and necessity requires the certification of the project as proposed by Michigan Wisconsin and the 12 suppliers. Considerations attaching to what is required by the public convenience and necessity, and what constitutes adequate proof thereof have been the subject of numerous Commission opinions and court review proceedings over the past several years since the Commission began its regulation of independent producers. It may be said, in general, that more certainly must be shown for a producer to obtain certificate authorization than the mere fact that the pipeline company to which it would sell the gas is ready, willing, able, and eager to get the gas, and that there was an absence of fraud or collusion in connection with the transaction which gave rise to the purchase. Also, it is clear from the various court decisions that the Commission must satisfy itself when a proposed transaction such as this comes before it that there will be no disturbance of the price structure for natural gas in the particular area, either by reason of the activation of the favored nations clauses or other automatic provisions of con-

tracts in the area or by the establishment of a new price level in the market area which all prospective buyers must meet or exceed if they have any hope whatever of acquiring additional supplies of gas. Much of the advice obtained from court decisions is necessarily of a negative nature because the courts do not attempt to supplant an agency's function. It is the function of the courts on review, speaking generally, to proscribe faulty treatment of a matter by the Commission, rather than to prescribe a course of action by a regulatory agency which would govern its future consideration of other cases.

In fairness to the producers in this matter, it should be noted that there has been an effort to provide good and sufficient reasons for the Commission to authorize this transaction by the issuance of a certificate without any condition. There has been presented considerable amount of data with respect to the geological conditions which affect the price in these new fields, and to demonstrate why the 19.5 cents initial price should not be considered as excessive.

One of the producers, Sinclair Oil and Gas Company, made an abbreviated cost of service presentation based upon hypothetical rates of return. This evidence purports to show that the proposed contract price in this proposal is well supported from a cost standpoint. The other producers did not undertake as ambitious a presentation in this regard as did Sinclair.

Discussion of the Evidence and Conclusions

The Prepayment Proposal

Michigan Wisconsin has prepaid to the producers $4,014,928.17 for one year's contract quantity of gas on the basis of one million cubic feet for each 4 billion cubic feet of presently proved reserves. In each contract there is a provision that if either party refuses to accept a certificate, the contract is terminated and the seller must refund the prepayments at 6 percent interest.

Michigan Wisconsin has the right to make up prepaid gas (a two-year supply based upon minimum contract deliveries) over the entire life of the contract and, if demanded, the seller must deliver daily quantities even in excess of the 125 percent of the average daily quantity specified in the gas purchase contract to the extent the seller's equipment, prudent operations and state conservation commission regulations permit.

On its face the prepayment plan advanced by the applicants herein has many plus features and no minus features. If all things were to work out as envisioned everyone involved in this transaction would receive benefits. Michigan Wisconsin would have gas "in the bank" so to speak, for future use when needed. The producers would have some of their money now instead of having to wait until the gas is actually delivered. Is there any reason why such an arrangement will be adverse to the interests of the customers attached to Michigan Wisconsin, to gas customers in general, or to the public at large? Is there anything inherent faulty with such proposed arrangements?

The Staff has attacked the prepayment feature on several grounds, one of which is that the true cost of prepaid gas would range from 20.7 cents to 45.1 cents per Mcf (depending upon the date the gas is actually taken). This increased cost is brought about by the addition of the interest component which might otherwise have been earned by the cash used for the prepayment or which Michigan Wisconsin must pay to lenders for the use of money in lieu of the money on deposit with the producers in the form of the prepayment. Thus, points out the Staff, the effect of the prepayment arrangement is to "transfer the burden of acquiring capital to the consumer." It is the position of the Staff that regardless of the justification for the initial price

of 19.5 cents, the gas on deposit with the producers is sure to cost more than 19.5 cents, possibly a great deal more, and these additional gas costs will be paid ultimately by consumers. The Staff points out that the inclusion of the prepaid provisions in the gas purchase contracts represents additional gain to the producer which might otherwise be reflected in an even higher initial contract price. Another point which the Staff has advanced is that the gas does not belong to Michigan Wisconsin by reason of its prepayments, and that it will not become the property of Michigan Wisconsin until it is reduced to possession. The Staff indicates that there are possibilities that this gas might never be available to Michigan Wisconsin by reason of drainage or the failure of wells to perform in accordance with the expectations. The Staff does not believe that Michigan Wisconsin would have any basis for a claim to retrieve the prepayments from the producer applicants in the event it became impossible for some reason for Michigan Wisconsin to get the gas.

Michigan Wisconsin has undertaken to answer the Staff in great detail in the various points it has presented. The company points out that the prepayments are based upon only proved reserves, and that the Woodward area being in its early stages of development will eventually contain as much as three or four times the present proved reserves. These prepayments, it is alleged, while geared to a particular volume of gas, were in fact related to all of the gas presently proved or to be proved in the Woodward area. Another point urged by Michigan Wisconsin is that the makeup of the prepaid gas will occur much faster than was assumed by the Staff and that the cost of the prepayments must be spread over a larger volume of gas than that used by the Staff if a meaningful figure of additional cost per Mcf is to be obtained under Michigan Wisconsin's view. It is quite probable that the reserves involved will amount to some 750,000,000 Mcf or more, and that in such case the additional cost of which may be related to the prepayments amounts to no more than two or three-tenths of a cent per Mcf.

Michigan Wisconsin has argued at considerable length to the effect that it will take make-up gas caused by contract-take deficiencies at a considerably greater rate than estimated by the Staff.[10] Michigan Wisconsin plans to make up deficiencies by taking 125 percent, or more, of a much higher daily quantity in subsequent years. Michigan Wisconsin believes that deficiencies in initial takes could be made up within a matter of a year or two after the commencement of the Phillips drop-off.

Michigan Wisconsin says that the Staff is in error in its contention that it would take three years to take all of the deficiency gas. The pipeline company is not limited to 125 percent of the average daily quantity in taking prepaid gas, but only to the limitations imposed by prudent operation of the wells. Michigan Wisconsin points out that the Staff has ignored the fact that the reserves, and hence the contract quantities, to be delivered are expected to triple or quadruple the initial volumes. Thus, while it would take nearly eight years to make up the prepaid gas at 125 percent of the daily contract quantity on the basis of the original reserve, it would take only two years to do so if the initial reserves are enhanced, as it is expected they will be.

Michigan Wisconsin points out another alleged fallacy in the Staff's calculation of the cost per Mcf of the prepaid gas. This fallacy is the assignment of all of the prepayment costs to approximately 20,000,000 Mcf of gas. Michigan

[10] Under the contracts, the early year deficiencies must be made up before any of the prepaid gas may be taken. As the recoverable reserves increase, the daily contract quantity increases proportionately.

Wisconsin points out that the prepayment represents less than 10 percent of initial proved reserves and on the basis of future increases in reserves, the prepayment will represent only four or five percent of total reserves. It is true, says Michigan Wisconsin, that the total amount of the prepayments was mechanically arrived at on the basis of a relatively small proportion of the proved reserves. This does not justify assignment of all prepayment costs to those particular Mcf's, Michigan Wisconsin claims. The prepayment was part of a package that included purchase of 238 billion cubic feet of proved reserves, plus all of the potential reserves underlying some 280,000 acres of land. Michigan Wisconsin has purported to demonstrate that on the basis of presently proved reserves the prepaid gas will all be delivered by the end of the eighth year at the very least. The reserves expected to be developed total 500,000,000 Mcf or more. Thus, on this basis the additional cost per Mcf attributable to prepayments will be less than three-tenths of a cent.

Michigan Wisconsin thus emphasizes the fact that these prepayments add "almost nothing" to the cost of the Woodward gas, and that the benefits Michigan Wisconsin shall have obtained in return are essential to its continued efficient and economical operation.

Michigan Wisconsin believes that the Staff's argument that it will realize a handsome margin of profit on the prepayment to be in error. It is the Staff's theory that Michigan Wisconsin can borrow money at 4.5 percent and 5.5 percent, and that by capitalizing the prepayments as a part of the rate base, Michigan Wisconsin will be earning over 6 percent, or a profit margin of approximately 2 percent on the prepayments. Michigan Wisconsin maintains that the prepayments, like any other dollar of rate base, are financed with both debt and equity capital costing an amount equivalent to the rate of return, and that there is no profit to Michigan Wisconsin from prepayments.

The Staff has also contended that there is a possibility that Michigan Wisconsin might find it impossible to take all of the prepaid gas, and would thus lose some or all of the prepayments. Michigan Wisconsin believes this possibility to be too remote for serious consideration.

While Michigan Wisconsin has pointed out one instance in a rate case where the Commission has approved the inclusion of prepayments of a certain type for inclusion in the rate base (*El Paso Natural Gas Company*, 22 FPC 260, 270) the fact is inescapable that the payment of this sum of $4,140,928 will have the effect of increasing the cost of all of the gas that Michigan Wisconsin will take from these producers in some unknown amount, depending on just when the prepaid gas will be actually taken into its system. As we have seen, Michigan Wisconsin has maintained that the prepaid gas will be taken within two years, probably, and at the very least before the end of the eighth year. The Staff, however, utilizes the most adverse condition in testing the proposition and has demonstrated how serious the price impact could be with respect to this gas if it were not taken until the latter years of the contract.

The prepayment proposal in this matter creates such an element of uncertainty with respect to the impact it will have upon the customers who will have to pay for it that it raises a serious question as to whether or not this kind of an arrangement is in the public interest and whether a certificate proposal which embodies such a proposition can be said to be *required* by the public convenience and necessity. It is not the function of the Commission to manage gas pipeline companies or to tell the management of pipeline companies either directly or indirectly how they must conduct their negotiations and transact their business. On the other hand, the responsibility of this regulatory agency with respect to rates (whether those rates are contained in a certificate application

of 19.5 cents, the gas on deposit with the producers is sure to cost more than 19.5 cents, possibly a great deal more, and these additional gas costs will be paid ultimately by consumers. The Staff points out that the inclusion of the prepaid provisions in the gas purchase contracts represents additional gain to the producer which might otherwise be reflected in an even higher initial contract price. Another point which the Staff has advanced is that the gas does not belong to Michigan Wisconsin by reason of its prepayments, and that it will not become the property of Michigan Wisconsin until it is reduced to possession. The Staff indicates that there are possibilities that this gas might never be available to Michigan Wisconsin by reason of drainage or the failure of wells to perform in accordance with the expectations. The Staff does not believe that Michigan Wisconsin would have any basis for a claim to retrieve the prepayments from the producer applicants in the event it became impossible for some reason for Michigan Wisconsin to get the gas.

Michigan Wisconsin has undertaken to answer the Staff in great detail in the various points it has presented. The company points out that the prepayments are based upon only proved reserves, and that the Woodward area being in its early stages of development will eventually contain as much as three or four times the present proved reserves. These prepayments, it is alleged, while geared to a particular volume of gas, were in fact related to all of the gas presently proved or to be proved in the Woodward area. Another point urged by Michigan Wisconsin is that the makeup of the prepaid gas will occur much faster than was assumed by the Staff and that the cost of the prepayments must be spread over a larger volume of gas than that used by the Staff if a meaningful figure of additional cost per Mcf is to be obtained under Michigan Wisconsin's view. It is quite probable that the reserves involved will amount to some 750,000,000 Mcf or more, and that in such case the additional cost of which may be related to the prepayments amounts to no more than two or three-tenths of a cent per Mcf.

Michigan Wisconsin has argued at considerable length to the effect that it will take make-up gas caused by contract-take deficiencies at a considerably greater rate than estimated by the Staff.[10] Michigan Wisconsin plans to make up deficiencies by taking 125 percent, or more, of a much higher daily quantity in subsequent years. Michigan Wisconsin believes that deficiencies in initial takes could be made up within a matter of a year or two after the commencement of the Phillips drop-off.

Michigan Wisconsin says that the Staff is in error in its contention that it would take three years to take all of the deficiency gas. The pipeline company is not limited to 125 percent of the average daily quantity in taking prepaid gas, but only to the limitations imposed by prudent operation of the wells. Michigan Wisconsin points out that the Staff has ignored the fact that the reserves, and hence the contract quantities, to be delivered are expected to triple or quadruple the initial volumes. Thus, while it would take nearly eight years to make up the prepaid gas at 125 percent of the daily contract quantity on the basis of the original reserve, it would take only two years to do so if the initial reserves are enhanced, as it is expected they will be.

Michigan Wisconsin points out another alleged fallacy in the Staff's calculation of the cost per Mcf of the prepaid gas. This fallacy is the assignment of all of the prepayment costs to approximately 20,000,000 Mcf of gas. Michigan

[10] Under the contracts, the early year deficiencies must be made up before any of the prepaid gas may be taken. As the recoverable reserves increase, the daily contract quantity increases proportionately.

Wisconsin points out that the prepayment represents less than 10 percent of initial proved reserves and on the basis of future increases in reserves, the prepayment will represent only four or five percent of total reserves. It is true, says Michigan Wisconsin, that the total amount of the prepayments was mechanically arrived at on the basis of a relatively small proportion of the proved reserves. This does not justify assignment of all prepayment costs to those particular Mcf's, Michigan Wisconsin claims. The prepayment was part of a package that included purchase of 238 billion cubic feet of proved reserves, plus all of the potential reserves underlying some 280,000 acres of land. Michigan Wisconsin has purported to demonstrate that on the basis of presently proved reserves the prepaid gas will all be delivered by the end of the eighth year at the very least. The reserves expected to be developed total 500,000,000 Mcf or more. Thus, on this basis the additional cost per Mcf attributable to prepayments will be less than three-tenths of a cent.

Michigan Wisconsin thus emphasizes the fact that these prepayments add "almost nothing" to the cost of the Woodward gas, and that the benefits Michigan Wisconsin shall have obtained in return are essential to its continued efficient and economical operation.

Michigan Wisconsin believes that the Staff's argument that it will realize a handsome margin of profit on the prepayment to be in error. It is the Staff's theory that Michigan Wisconsin can borrow money at 4.5 percent and 5.5 percent, and that by capitalizing the prepayments as a part of the rate base, Michigan Wisconsin will be earning over 6 percent, or a profit margin of approximately 2 percent on the prepayments. Michigan Wisconsin maintains that the prepayments, like any other dollar of rate base, are financed with both debt and equity capital costing an amount equivalent to the rate of return, and that there is no profit to Michigan Wisconsin from prepayments.

The Staff has also contended that there is a possibility that Michigan Wisconsin might find it impossible to take all of the prepaid gas, and would thus lose some or all of the prepayments. Michigan Wisconsin believes this possibility to be too remote for serious consideration.

While Michigan Wisconsin has pointed out one instance in a rate case where the Commission has approved the inclusion of prepayments of a certain type for inclusion in the rate base (*El Paso Natural Gas Company*, 22 FPC 260, 270) the fact is inescapable that the payment of this sum of $4,140,928 will have the effect of increasing the cost of all of the gas that Michigan Wisconsin will take from these producers in some unknown amount, depending on just when the prepaid gas will be actually taken into its system. As we have seen, Michigan Wisconsin has maintained that the prepaid gas will be taken within two years, probably, and at the very least before the end of the eighth year. The Staff, however, utilizes the most adverse condition in testing the proposition and has demonstrated how serious the price impact could be with respect to this gas if it were not taken until the latter years of the contract.

The prepayment proposal in this matter creates such an element of uncertainty with respect to the impact it will have upon the customers who will have to pay for it that it raises a serious question as to whether or not this kind of an arrangement is in the public interest and whether a certificate proposal which embodies such a proposition can be said to be *required* by the public convenience and necessity. It is not the function of the Commission to manage gas pipeline companies or to tell the management of pipeline companies either directly or indirectly how they must conduct their negotiations and transact their business. On the other hand, the responsibility of this regulatory agency with respect to rates (whether those rates are contained in a certificate application

or are the subject of inquiry in a rate case) should be clear; *i.e.*, there should be no approval of a rate which unnecessarily contains indefinite elements of cost.[11] As has been observed heretofore, while the prepayments method as it has been described and outlined by Michigan Wisconsin and the producer applicants, *appears* to be the only way that Michigan Wisconsin can make arrangements now for a certain supply of gas to replace the Phillips drop-off as this drop-off occurs in future years, the element of indefiniteness of the real cost of the prepaid gas is a disturbing aspect. It may be true that as the matter finally develops, the additional cost of gas by reason of this prepayment arrangement may be a *de minimis* matter. But we do not know this now, nor is there any possible way of demonstrating that the results will be as favorable as Michigan Wisconsin anticipates they shall be.

One of the cardinal elements of rates and rate making is that a filed rate should be one which is definite and certain to the greatest degree possible. There may be factors which the regulatory agency cannot anticipate which will have a bearing upon the stability of a filed rate. However, if there are known factors which are certain to have an adverse effect upon the rate structure it is believed that the Commission should take whatever steps are available to it to protect the rate payer before approving a transaction which will give rise to additional costs and thus to potentially higher rates.[12]

It does not appear that the proposal for prepayments, attractive though it may be, has been shown to require approval in its present form. It not only provides the producers with an interest-free loan (which might be tolerated) but a loan of an unknown magnitude for which no account has been taken in the initial rate provided for in the contracts. It might be suggested that such prepayment proposal might have been acceptable if the prepayments were agreed to constitute a simple credit to be applied against the *first* deliveries of gas under the contracts. In this way, it could be known with certainty that the prepaid gas would be taken because it would be the first to be delivered. The producers would have the use of Michigan Wisconsin's prepayment money for a period of one to two years, at least and probably more, and such use should more than compensate them for the reservation and commitment of this gas to Michigan Wisconsin. This proposal, however, would require a virtual rewriting of this aspect of the contract. This is suggested only as a possible avenue of solution for the problem of indefiniteness which this prepayment arrangement has posed.

In order that there will be no question raised as to the basis for the disapproval or rejection of this prepayment arrangement herein, it may be stated once more that it is believed that the prepayment arrangements as proposed herein would have the practical effect of enhancing the initial price of the gas to a price per Mcf in excess of the amount stated in the contracts. Michigan Wisconsin has agreed in its briefs that the advancement of these funds to the producers can be translated into additional cost of the gas on an Mcf basis. It has argued persuasively that this additional cost will be sure to be *de minimis*. However, the public interest requires that this agency in considering

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[11] Unless, of course, the rate is designed as a cost-of-service rate, subject to revision at a later date based upon actual historical data. This type of rate, utilized by the Commission in a few instances, has been avoided like the plague, whenever it has been proposed.

[12] There is constant reference to the claim that this transaction or the prepayment aspect will have no effect on Michigan Wisconsin's rates. It is evident, however, that if this company can toss out in excess of four million dollars, which will be non-revenue producing for some period up to twenty years, and, conceivably might not ever be retrieved, that some rate adjustments might be in order eventually.

a proposal such as this is to consider the potential effect on the consumer of the worst possible eventuality. Under the facts of this case, such an eventuality would be that the prepaid gas would not be taken at all, or if taken, might be taken so near to the end of the twenty-year contract period, that the true cost per Mcf would be exorbitant.

The certificate approval in this matter shall therefore be conditioned upon the submission to the Commission of contracts without such prepayment features or with prepayment features modified in such a way as to eliminate the dangers which have been suggested herein and by the Staff.

The Producer Applications

While the pipeline company in this proceeding is primarily interested in obtaining certificate approval for its own proposed facilities, it is just as vitally interested in the success of the twelve producer applicants with which it has contracted and upon which its proposal depends. The twelve independent producer applicants must each have certificate authorization to sell gas under Michigan Wisconsin under the terms and under the conditions as set forth in their contracts.

Primarily, it must be remembered that a pipeline company, such as Michigan Wisconsin when faced with a shortage in its gas supply, either present or anticipated, is so intent upon obtaining additional gas that it does not wish to be put in the role of a hard bargainer for fear it will jeopardize its economic future.

As has been remarked before by this Examiner,[13] these pipeline-producer transactions do not have the usual elements of bargain and sale. Because there usually is competition among the pipeline companies for particular reserves of gas, there must be some sweetening added to an offer in order to induce the commitment of gas supplies as competing purchasers frequently offer the same cents per Mcf. In such circumstances a pipeline company does not think in terms of saving cents or fractional cents, but rather, thinks of what the offer should be that will sew up the deal. This kind of thinking sometimes leads to overshooting, for safety. Yet a fraction of a cent multiplied by millions of cubic feet of gas can have a cost of service impact of staggering proportions. It is therefore incumbent upon the regulatory agency which has been given the duty and responsibility of reviewing these matters prior to approval to give consideration to the over-all picture, not to the deficiencies of a particular pipeline company, no matter how serious those deficiencies may seem to be.[14] Nor can the agency, in the public interest, be affected in its consideration by feelings of generosity.

This is an area which is fraught with problems. There is always the threat which hangs over all gas purchase transactions subject to regulation that if this Commission is unduly restrictive in the conditions it seeks to impose, the producer applicants will decline to sell their gas in interstate commerce. Whether the threat of such withdrawal of gas is real or imaginary in a particular situation cannot be told in advance. In this matter Michigan Wisconsin paints a picture of itself with its back to the wall, and urges that if the Commission tampers with this porposal in any considerable degree the chances that it has to operate its pipeline at a similarly low cost will be lost, possibly forever. Whether

[13] E.g., Intermediate Decision 6/24/55, *Cities Service*—Signal, G–2569–70 at p. 11 (mimeo) (apocryphal); Intermediate Decision 6/17/58, *Seaboard Oil Company et al*, G–13169, 20 FPC 330, 332 fn 4; Intermediate Decision 1/29/60, *Humble Oil*, G–15227, at p. 4 (mimeo).

[14] As stated by the Examiner in the *Humble Case*, G–13679 *et al.* 24 FPC 191, 195, at p. 201 (which has become effective as the Commission's opinion) "The willingness (of the pipeline) to pay more for gas, even though such higher payments will result in advantages or savings to it, is not a basis on which rates to be charged by producers can be justified."

or not such rejection will occur in this case if a condition, or conditions, are imposed is something which cannot be known at this time.

The 19.5 cents proposal in this proceeding is the crucial matter for Commission determination. The methods of analysis of initial certificate prices are still evolving, and may continue to be in a state of flux for some time to come. The Commission has issued several policy statements with respect to its intentions in the matter of gas pricing, among which are plans to establish area prices which will provide a base line for the consideration of gas sales proposals in the respective areas. Whether this approach by the Commission will prove to be workable or unworkable, only time and experience will tell. Thus it is difficult at this stage of the evolution of gas pricing by the Commission to make a thorough and informed analysis of the proposal herein.

The 19.5 cents per Mcf exceeds the initial prices promulgated by the Commission in its Statement of General Policy 61–1 by as much as 4.5 cents per Mcf for those sales originating in Dewey, Woods, Major and Alfalfa Counties in Oklahoma, and by 2.5 cents for those sales proposed to be sold from Woodward County in Oklahoma.

The Staff has recommended the approval in this case of a 17 cent price for Woodward County gas and a 15 cent price for gas originating in the "other" Oklahoma counties involved herein. The effect of the Staff's recommendation is to reject the arguments by Michigan Wisconsin and the producer applicants to the effect that the price line set up by the Commission in its policy statement is unrealistic, unreasonably low, and that scant attention, if any, should be paid to it in the resolution of this matter.

As has been observed before, the 19.5 cents involved here seems to have arisen from the fact that this is the second step in the periodic price schedules in the Laverne Field gas purchase contracts. The Laverne contracts, therefore, provide the only point of reference used by Michigan Wisconsin and the producers in arriving at the gas price above the 17 cent base figure, rather than 18.5, 19.0, or some other intermediate point in excess of the 17 cent figure. The foregoing illustrates the imprecision which characterizes these gas sales transactions. Presumably, if the second step in the Laverne contracts had been 21.5 cents, or some other figure, it would have been *that* figure which would have been used for the initial contracts herein. Having developed an acceptable initial price, Michigan Wisconsin and the independent producers here involved must attempt to work backwards and to justify this override on the initial Laverne contract price by showing the principal differences in the cost considerations affecting the Woodward Field. However, these justifications, impressive though they are, have no mathematical significance in that one or two cents either way could have been justified as easily as the 19.5 cents has been.

The geologic testimony contained in the record seems to support the producers in their contentions that they are entitled to a higher price per Mcf for Woodward gas in the initial contract than for the Laverne gas.

Michigan Wisconsin and the producers together argue that all consideration of the 19.5 cent price proposed herein must begin with a premise that the Laverne Field 17 cent price is a base or floor from which all consideration must spring. The Woodward area adjoins the Laverne area of Harper and Beaver Counties in Oklahoma, and as Michigan Wisconsin points out, the evidence in this case is undisputed that the Laverne area of Harper and Beaver Counties and the Woodward area of Woodward and Ellis Counties for which 17 cent prices have been certificated by this Commission are closely related both geologically and as pipeline market areas.

The Woodward area, like the Laverne area, is located on the north flank of the Anadarko Basin and involves production from the same formations. The record shows that the northern part of the Woodward area (Woods County) is structurally similar to the Laverne area and that in the remaining part of the Woodward area (Woodward, Major and Dewey Counties) the same producing zones exist, but become increasingly deeper to the south.

The burden of testimony also demonstrates that the Laverne and Woodward areas represent common marketing areas for natural gas. A number of the expert witnesses for the producers testified convincingly as to the lack of difference in marketing areas between the Laverne and Woodward areas. There is persuasive evidence in the record in the form of expert opinion that the Oklahoma Panhandle and the Woodward area are a part of a single gas marketing area. If this indeed be so, the price line as established by the Commission in the Oklahoma Panhandle area as being 17.0 cents per Mcf would be applicable to the sales involved here. As mentioned before, it is the general contention by the producers that the market areas or price areas set up by the Commission in its policy statement are not realistic and that therefore they have limited value in judging the proposed transactions reflected herein. For the purposes of this case, at least, it is contended the division lines set forth in the Commission's policy pronouncement should be ignored.

It is possible in a matter of this kind by shifting boundary lines around, by drawing comparisons between one county which is within one boudary and another county which is outside of the boundary line, and by including information with respect to the geological areas, to make a shambles of the reasonableness of the boundary lines of any particular price area. The evidence in this case, as well as others, clearly suggests that no matter what basis might be used for the delineation of a price area, it would be quite possible to marshall facts and persuasive arguments to illustrate the arbitrary aspects of the area selected. One of the problems with which the Commission may always be faced in fixing boundaries for area prices will be that no matter where the lines are fixed, there will be producers on the other side of the line, perhaps only a short distance away, who will allege that the line is arbitrary, unreasonable, and should be disregarded in analyzing the fairness of *their* contracts.[15]

Despite the discrepancies between the Commission's area price boundaries and the boundaries of the market or pricing areas urged herein, it would appear that the contention that the "price line" in the Oklahoma Panhandle area of 17.0 cents per Mcf should apply to the entire Woodward area is well founded. The base price which has been utilized by the Commission for Woodward County is 17 cents. There are a large number of sales being made from the Laverne Field at an initial base price of 17 cents per Mcf under permanent certificates which are not in the process of review. The Commission has relied upon the Laverne area price of 17 cents as establishing the appropriate level in the area in Opinion #328, (*Transwestern Pipeline Company et al.*, 22 FPC 391). The Commission issued permanent certificates conditioned to a base price of 17 cents per Mcf to producers proposing to sell gas to Transwestern in an area which includes Woodward, Herbert, Ellis and Beaver Counties, Oklahoma, relying specifically on the 17 cents sales to Michigan Wisconsin in the Laverne Field area. In the matter of *Gulf Oil Corporation et al.*, 23 FPC 664, 926, certain producer applications were submitted to the Commission which resulted in a reduction of the proposed price to 17 cents per Mcf for sales in the Glick Field located in

[15] cf. *Natural Gas Pipeline Company of America*, 24 FPC 244, fn. 7.

south central Kansas immediately north of the Woodward area. The certificates were refused and the gas is being sold in intrastate commerce.

While it would appear that the Woodward County price has been established as being 17 cents, and the Woodward area other than Woodward County has a lower price, if sales are considered on a purely statistical basis (the Staff witness in this case differentiated between the Oklahoma Panhandle area as set forth in the Commission's Statement of General Policy 61–1 and the Oklahoma [Other] area in which he placed the Woods, Major and Dewey Counties' sales) the contention of the applicants that this is a mechanical approach which cannot be justified, and the evidence in this matter which is to the effect that the entire Woodward area is the same or closely analogous geographically, geologically, and as a marketing area to Harper, Beaver and Ellis Counties is very persuasive.

Michigan Wisconsin treats the Woodward area as a single unit and believes that while there may be some historical differences with respect to pricing, that the entire area should be considered as a single unit for pricing purposes in this case. Michigan Wisconsin would like to consider the whole Woodward area as being included within its future, not just the initial proved reserves which are located in scattered fields adjacent to its pipeline. The contracts in this case contain large acreage dedications and the producers have submitted testimony to the effect that they intend to fully explore and to develop the acreage. It is Michigan Wisconsin's belief that a somewhat different treatment should be accorded such a major program than that given to relatively small sales from existing fields to nearby pipelines. The contracts relied upon by the Staff in its historical summary are, according to Michigan Wisconsin largely small scattered sales from individual wells or fields, some of which could be classified as "distress" sales. Michigan Wisconsin emphasizes the point that its proposal herein represents a large acreage dedication contemplating extensive future development for the benefit of a single pipeline. The five largest acreage dedications involved in this case range from 97,500 acres by Pan American to 23,000 acres by Sunray. This has been compared by Michigan Wisconsin to five of the largest acreage dedications involved in the Staff analysis which range from 3,137 acres to 1,995 acres.

The evidence in this matter justifies the conclusion that all of the contracts involved in Michigan Wisconsin's proposal should be treated on the same price level despite the historical differences shown by the Staff's exhibit for the areas involved here other than Woodward County. Woods, Major and Dewey Counties shall be considered to be in the "Oklahoma Panhandle" area for the purposes of this case.

Turning now to the matter of whether or not there has been a showing which would justify 19.5 cents as the initial price in this transaction, Michigan Wisconsin urges that there are three principal reasons why costs of production are higher in the Woodward area than in Laverne, and that therefore some additional price consideration should be paid for the Woodward area gas. These reasons are: (1) the producing formations are deeper; (2) the producing sands in the Woodward area are scattered and lenticular rather than blanket sands and do not lend themselves to multiple completions; (3) the general trend of costs of production (everywhere) continues to rise.

There is no question but that the record contains persuasive evidence to the effect that to obtain production, well depths must be greater in the Woodward area than in the Laverne Field. Presumably, with potential producing formations at greater depths, costs of production are increased. The Witness Peterson testified that in the Laverne area about 67 percent of all production

is at less than 6,000 feet, whereas in the Woodward area there is no production less than 6,000 feet, and 55 percent of all production is below 8,000 feet. It would appear that depth of wells could be an important consideration in justifying an increase over the 17 cent Laverne Field price if there were any logical way that this additional cost could be related precisely to the increase in price. However, merely to say that because the wells have to be deeper there should be a greater price charged for the gas from those wells is not enough. There must be some rational formula used to relate the depth of wells to the price to be charged, otherwise the sky would be the only limit.[16]

There were various witnesses who testified that the success ratio in the Woodward area is notably lower than in the Laverne area. Multiple sands are found much less frequently in the Woodward area than in Laverne. The absence of such multiple sands cuts down the number of dual and triple completions which are possible to be made. This also lowers the amount of average reserves per productive well. The record contains cost information with respect to the average cost of drilling and completing a productive well in the Woodward area as compared to the Laverne area. This testimony in evidence establishes without much question that operations in the Woodward area thus far, at least, are more costly than similar operations in the Laverne area. All of this information points inescapably to higher costs in the Woodward area and would seemingly justify a higher initial price than for the Laverne area *if there were any logical way of tying this information into the price proposed herein as an initial contract price.* However, the evidence presented would justify, perhaps, 17.5 cents per Mcf, 18.5 cents, or 21.5 cents just as well as 19.5. The producers thus are not able to relate their needs for additional revenues to the particular amount which they maintain they must have, and which they say the public convenience and necessity requires herein, *i.e.* an initial price of 19.5 cents per Mcf.

The foregoing discussion might be construed as being critical of the producers herein for not having provided a more dependable and precise method for analyzing their proposed 19.5 cents contract price. It is not so intended, for the producers herein have been candid and forthright in their respective presentations, and have utilized considerable ingenuity in attempting to justify the extra 2.5 cents over the Laverne Field price.[17] If cost has any important bearing in the assaying of a proposal of this kind, the only cost worthy of real consideration would be a unit cost of a particular gas supply. It has been recognized by all concerned in this matter that the development of a reliable unit cost for this Woodward area gas would be impossible at this time, inasmuch as the quantity of gas covered by the contracts is uncertain, few development wells have been drilled, much undeveloped acreage is involved, and there has been no producing experience. As pointed out by counsel for Amerada in their brief, even if sufficient information were available to develop a direct unit gas cost, the difficult and uncertain problems of allocation which must be resolved to determine a reliable unit gas cost would remain. A unit cost presentation, if prepared properly, and with the care necessary to eliminate error to the greatest degree possible, would turn a certificate case into a rate case. The possibility of such a transformation has been the subject of much

[16] Cf. 24 FPC 245 (fn 10).

[17] The whole difficulty lies in the lack of known standards and the absence of a prescription of the proof a producer applicant is expected to present. The Sinclair type of proof perhaps comes closest to what eventually may be required of all producers seeking certificates. But the Sinclair proof also comes very close to the same kind of presentation which would be appropriate in a producer rate case.

thought and consideration since the beginning days of producer regulation.[18] It is not one which may be looked forward to with relish. For if this cumbersome, time consuming method of producer rate analysis ever becomes necessary, it is very doubtful that the industry will be able to maintain its present vigor and growth pattern.

It is well recognized by all of the courts which have wrestled with this problem that while there are many aspects of the initial price or rate study by the Commission in a certificate proceeding which may partake of some of the same aspects involved in a determination of what constitutes a "just and reasonable" rate in a Section 4 rate proceeding, there are important differences which make it extremely doubtful that there will ever be a feasible means developed to ascertain whether or not an initial rate will eventually become a "just and reasonable" rate.

In the absence of a reliable unit cost for gas, the regulatory agency is thrown back into a morass of highly uncertain and speculative factors[19] which it is expected to apply to a proposed contract price, and to arrive at a determination of an initial rate which will be both consistent with the public interest from the consumers' standpoint, and which at the same time will preserve the vitality of one of the nation's most important extractive industries.

It is not appropriate or feasible to suggest herein an easy solution for this basic problem which has changed very little in the days and years since the Supreme Court's Phillips decision. It is quite apparent that as of this time very little headway has been made in the solution of this difficult problem. There could be no possible disagreement by any of the lawyers, accountants, engineers, economists, and members of regulatory agencies which have wrestled with this problem over the years, with the observation that there is no easy solution, if in fact there is any solution at all.

For the time being, therefore, until more sophisticated methods are evolved to analyze proposed initial producer rates, we shall have to utilize the admittedly make-shift area price ceiling approach. This is not a happy solution to the matter, nor in any sense can it be a permanent one. The area price approach as it is now evolving appears to have some regard for the income requirements of the producing element of the natural gas industry in general. Yet to be developed are ways in which this industry-wide information, even limited to a particular area, can have any rational significance or usefulness in a particular case due to the wide differences among various producers with respect to the skills, techniques and internal management philosophy.

This decision will provide for the issuance of certificates to producers herein for sales of gas from the Woodward area at a price not to exceed 17 cents per

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[18] Section 4(a) declares that all rates for the sale of natural gas subject to the jurisdiction of the Commission which are not just and reasonable are unlawful.

[19] Some of the intangibles which Michigan Wisconsin and producers urge as being factors which illustrate the beneficence of the proposed arrangement are reminiscent of the "value of service" concepts of rate making. "This phrase" says the Commission in its order of April 7, 1961, in E–6816, "is sometimes used in referring to the discredited theory occasionally advanced to justify rates above the seller's cost-of-service." Regulation, says the Commission, in *South Carolina Generating Company,* 16 FPC 52, 58, based upon cost to the buyer of supplying substitute power, *i.e.,* "value of service, would in fact be no regulation at all and would completely disregard the public interest and the ultimate consumer which the Act is designed to protect."

Would it not be fair to say that approval of the 19.5 cent rate proposed herein if based, in part, upon the desirable delivery and prepayment arrangement, as well as the higher cost of gas which Michigan Wisconsin might have to pay its other suppliers if the Phillips drop-off is awaited, rather than on the unit cost of gas of the producer, would likewise be subject to the same criticism?

Mcf with appropriate tax reimbursement. The 17 cents is the same as the Laverne figure and this has been acknowledged by all concerned to be the lowest price for this gas that can be realistically used in this matter as a point of departure.[20] It should be repeated parenthetically that this 17 cent price is higher than that which is called for by the Commission's Policy Statement 61–1 for "Oklahoma (Other)." However, the Woodward area appears to be a single pricing area from a geological and marketing standpoint and there has been no reason shown for distinguishing between portions of this area on the basis of pure geography and historical sales of relatively small quantities of gas at 15 cents.

With periodic increases in these contracts, just as in the Laverne contracts, there is no reason to believe that when and if the periodic step increases become due, a filing for the increased rates, based upon unit cost data and experience in this field, which will be available by that time, will receive careful consideration by the Commission. The facts and figures developed from actual operating experience will provide a basis for judgment of the rates which will be equitable to both consumer and to the producers. Only actual cost experience data will provide a logical, rational and defensible way of arriving at the determination of rates which are equitable from the standpoint of seller and buyer as well as that of the ultimate consumer.

The Btu Adjustment and Processing Agreement

The final matter requiring consideration herein is the question of whether or not the public convenience and necessity will permit the inclusion of Btu adjustment feature in the contracts which Michigan Wisconsin has entered with the producer. This Btu adjustment is actually an adjustment outside of the 19.5 cents proposed in the contract and is based upon the price of 1/100 cent per Mcf for each additional Btu over 1000.

The Staff, along with its other recommendations in this matter recommends that any certificate proposed herein be conditioned upon the revision of the contract to eliminate the Btu adjustment provisions.

There is a great deal to be said for the Staff's position. Logically, it would seem that a Btu adjustment provision is another indefinite enhancement on the basic price which is not reflected in the basic price but is as much of a charge upon the consumer of the gas as the basic rate would be. In principle, therefore, the elimination of the Btu adjustment provision would be a very desirable thing. A basic *desideratum* of a filed rate schedule, is it be in such form that anyone examining it should be able to ascertain exactly what the rate is without reference to anything outside of the rate schedule. Obviously, a Btu adjustment feature of a rate causes the rate to rise and fall and therefore the actual effective rate as of any one point of time is impossible to ascertain from an examination of the schedule.

There is some discussion in the briefs of the parties and of the Staff with respect to what effect Btu content higher than 1,000 would have upon the operation by Michigan Wisconsin. It is apparent that in some cases, at least, excessive Btu's may be an undesirable quality of the gas, and instead of enhancing the value or usefulness of the gas in the pipeline it can actually cause some oper-

[20] Laverne would be a better point of departure if the rates therein had been tested in a conventional rate case, and a finding made that they are "just and reasonable." While Laverne rates are not "suspect" in the sense that word is generally used, they are subject to revision downward. At the very least, the 2.5 cents periodic increase may not receive approval in whole or in part when this is filed for as a rate change.

ating difficulties which would be avoided if the gas were delivered on a uniform Btu basis by the seller.

We need not get into the pros and cons of this aspect of the matter inasmuch as this decision shall approve the Btu adjustment feature of these contracts in view of the fact that the sale here is being made to conform as nearly as possible to the terms and conditions of the Laverne Field sale, including price. The Laverne Field sales of gas to Michigan Wisconsin were certificated with inclusion of the Btu provision. It would seem that the Btu adjustment feature would be as appropriate here as it is in the Laverne situation, and the evidence seems to indicate that Btu adjustments are customary for sales made in this general market area of Oklahoma.

Another factor which is influential in the matter of allowing the Btu adjustment feature to subsist is the fact that there is a processing agreement between the producers and Michigan Wisconsin which will permit the producers to construct a stripping plant at a central point in the Woodward area to which Michigan Wisconsin will deliver the raw gas to the operators for stripping. The agreement between the pipeline company and the producers provides a method by which Michigan Wisconsin will be compensated for shrinkage, fuel and loss of Btu. The payment to Michigan Wisconsin for the loss of Btu is the same as that which is provided in the basic sales contract for payment to the producers.

It is the opinion of Michigan Wisconsin's officials that in practice the operation of the processing agreement will serve to "wash" any difference between the basic price and the price Michigan Wisconsin would pay as a result of additional Btu's. It is believed that the gas which will be derived from these producers' wells will be of a quality that will make it quite profitable to conduct stripping operations and that if the producers do not elect to erect a stripping plant, Michigan Wisconsin will probably do so and thus will derive the profits from such stripping operations which may be applied as a credit against the cost of the gas.

In the circumstances, therefore, the Btu adjustment provisions of these contracts do not seem to produce a result which would be contrary to the public interest, and therefore the certificate authorizations provided for in this decision will not contain any condition eliminating the Btu adjustment feature.

Conclusion

Simply restated, it is the conclusion herein that the arrangements proposed by Michigan Wisconsin should be approved by the Commission if certain modifications are made in the contracts which form the basis of these applications. In general, while it has been shown that the proposal by Michigan Wisconsin to purchase the Woodward area gas is highly desirable and should be undertaken in order to alleviate the anticipated drop-off in Phillips deliveries, the prepayment provision of the arrangement has not been shown to be in the public interest inasmuch as it injects into the basic price an additional cost, of an undetermined amount, which will be ultimately borne by the consumers of the gas. This provision, therefore, must be eliminated and prepayment moneys refunded to Michigan Wisconsin, or the agreement must be modified so as to provide that the prepayments constitute a simple credit against the first deliveries of gas under the contracts. In this way the prepayments would not be an indefinite liability to the customers of Michigan Wisconsin.

The 19.5 cent price proposed by Michigan Wisconsin and the producers does not have any definite or ascertainable relationship to the cost of producing the gas. While there has been shown a reasonable basis for belief that the unit cost

of production of gas from the woodward area fields will ultimately be higher in some indefinite amount due to particular geological differences between the Woodward area and the Laverne Field, and there must be an acknowledgement of a general upward trend of costs for the production of gas throughout the United States brought about by the fact known to all that as readily obtainable gas supplies become scarce, deeper drilling and more difficult operations are required to get gas supplies, it has not been shown that a basic price of 17.0 cents per Mcf plus the step-increases provided in the contracts every five years will not fully compensate the producers for the gas they expect to get from the Woodward area wells.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission as provided for in its Rules of Practice and Procedure, that:

(A) A certificate of public convenience and necessity be, and the same is hereby issued, authorizing Michigan Wisconsin Pipe Line Company to construct and operate the facilities desired in its application filed on September 30, 1960, subject to the jurisdiction of the Commission for the transportation of natural gas as therein set forth upon the terms and conditions of this order.

(B) Certificates of public convenience and necessity be, and the same hereby are issued upon the terms and conditions of this order to: Pan American Petroleum Corporation, Shell Oil Company, Sinclair Oil & Gas Company, Wilcox Oil Company, The Atlantic Refining Company, Kerr-McGee Oil Industries, Inc., Skelly Oil Company, Woodson Oil Company, Amerada Petroleum Corporation, Sun Oil Company (Mid-Continent Division), J. M. Huber Corporation and Sunray Mid-Continent Oil Company authorizing the sale by each of them of natural gas to Michigan Wisconsin Pipe Line Company from the sources set forth in their applications filed herein, in interstate commerce for resale, together with the operation of any facilities used in making such sale and performing such transportation which are subject to the jurisdiction of the Commission.

(C) The certificate granted in paragraph (A) hereof shall be accepted in writing and under oath by a responsible official of Michigan Wisconsin. The general terms and conditions set forth in paragraphs (a), (b), (c)(1), (c)(3), (c)(4), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act shall attach to the issuance of the certificate granted in paragraph (A) hereof, and in the exercise of the rights granted thereunder.

(D) The certificates granted in paragraph (B) hereof shall be granted upon the express condition and requirement that each of the independent producers named in paragraph (B) shall file rate schedules with the Commission within 30 days from the issuance of this order providing for a rate not exceeding 17.0 cents per Mcf plus appropriate tax reimbursements for natural gas delivered and sold to Michigan Wisconsin from the Northeast Cederdale Field of Major and Woodward Counties, the Northeast Seiling Field of Major County, the Northwest Chester Field of Woodward County, the West Campbell Field of Major County, and Lenora Field of Dewey County, all in Oklahoma, otherwise the order in this proceeding shall be null and void in its entirety and shall have no effect.

(E) The certificates granted in paragraph (B) hereof shall be granted upon the express condition and requirement that the independent producers named therein and Michigan Wisconsin Pipe Line Company shall mutually rescind their agreement to pay and to receive certain moneys for quantities of natural gas before such gas is delivered, as set forth in the so-called "Supplemental Agreement" or shall modify such supplemental agreement so that any

prepayments made pursuant thereto shall be credited against the first deliveries of gas under the various contracts.

(F) The certificates granted in paragraph (B) hereof shall be accepted in writing and under oath by a responsible official of each of the producer applicants named therein, within 30 days from the date of issuance of this order, and shall be subject to the general terms and conditions set forth in subparagraphs (a) and (e), Section 157.20, of the Commission's Regulations under the Natural Gas Act.

WILLIAM J. COSTELLO,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

TEXACO-SEABOARD INC., ET AL., DOCKET NO. G–13169 ET AL.;[1] TEXAS GAS EXPLORATION COMPANY ET AL., G–17336 ET AL.;[1] REPUBLIC NATURAL GAS COMPANY ET AL., G–16540 ET AL.;[1] THE CALIFORNIA COMPANY, G–16108; THE SUPERIOR OIL COMPANY, G–16388; SUNRAY MID-CONTINENT OIL COMPANY, G–14753; SUN OIL COMPANY, G–15122; THE SUPERIOR OIL COMPANY, G–16380; AREA RATE PROCEEDING, AR61–2

ORDER DENYING REHEARING SEVERING AND CONSOLIDATING PROCEEDINGS AND PROVIDING FURTHER PROCEDURES

(Issued March 7, 1962)

Our order of January 10, 1962, 27 FPC 10, in three groups of proceedings (Docket Nos. G–13169 *et al.*, G–17336 *et al.*, G–16540 *et al.;* see Appendices I, II, and III hereto) declared, *inter alia* an obligation to make refunds on the part of the producer-applicants in those proceedings. Numerous parties have filed applications for rehearing.[2] Our order of February 14, 1962, granted rehearing upon the applications filed by Pan American and the New York Public Service Commission so that we might consider all objections to our order of January 10 at one time. The various applications for rehearing persuade us to prescribe further procedures designed to abbreviate the duration of applicants' refund uncertainties. Otherwise, the applications contain no facts or arguments which call for modification of our January 10 order and should be

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[1] See Appendices I, II, and III for a complete listing of applicants and docket numbers.

[2] Pan American Petroleum Corporation; Public Service Commission of the State of New York; Phillips Petroleum Company; Kerr-McGee Oil Industries, Inc.; Cities Service Production Company; Long Island Lighting Company, Philadelphia Electric Company, and The United Gas Improvement Company ("The Eastern Seaboard Companies", jointly); Humble Oil & Refining Company; Austral Oil Company; Hassie Hunt Trust, Operator, *et al.;* Placid Oil Company; Continental Oil Company and Newmont Oil Company (jointly); J. R. Frankel *et al.*, now Berkshire Oil Company; Socony Mobile Oil Company, Inc.; Shell Oil Company; Amerada Petroleum Corporation; Tidewater Oil Company; Sohio Petroleum Company; Phillips Petroleum Company and Southern Natural Gas Company (joint venture); Sun Oil Company; Union Oil Company of California; Caroline Hunt Sands and Loyd B. Sands; Beck Oil Company *et al.;* J. Ray McDermott and Company, Inc.; Callery Properties, Inc.; Continental Oil Company; Mississippi River Fuel Corporation; Kilroy Properties, Inc., *et al.*, Ocean Drilling & Exploration Company (Operator), *et al.*, Bel Oil Corporation, and Sid W. Richardson d/b/a Richardson & Bass (Operator), *et al.* (jointly); and Texas Gas Exploration Corporation, *et al.*

denied. See *Socony Mobil Oil Company, Inc.*, order issued September 25, 1961, in Docket No. G–13780.

Applicants misapprehend the powers asserted by us in our January 10 order. Thus Austral Oil Company complains of our so-called "entrapment" here:

> * * * If such a procedure were valid, the Commission could simply issue unconditional certificates, as it has done in this case, and then after the producer has commenced deliveries, summarily issue h'm a new temporary or permanent certificate subject to the condition that he refund all amounts in excess of the initial rate ultimately determined to be proper in some later proceeding. Thus, the producer would be effectively denied a free choice to accept or reject such conditioned certificate and would be given no opportunity to present evidence to support his initial contract price prior to the imposition of the refund condition. * * *

Our January 10 order asserts no such general power to modify final orders, properly issued after hearing pursuant to Section 7(c) of the Natural Gas Act. The special history of these three groups of proceedings defines the limited power of modification involved here. In every case the statutory hearing has already been held and the producers afforded an opportunity to adduce evidence supporting their price proposals. Our unconditional certificate orders under Section 7 were erroneously issued in the first place and as a result of the invocation of Section 19 have never assumed finality. (The provisions of Section 19 sharply distinguish this Act from the statute construed in *C.A.B.* v. *Delta Air Lines*, 367 U.S. 316.) Obviously the substantive errors were ours in accepting the arguments propounded by the producer applicants; equally obvious, the New York Public Service Commission and the Eastern Seaboard Companies[3] have consistently, publicly, and in the final analysis successfully urged the error of these arguments. The courts having lain bare the errors, it remains our task equitably to correct them. See *Ford Motor Company* v. *N.L.R.B.*, 305 U.S. 364. Where we grant rehearing under Section 19(a) we may modify our order without further hearing; a judicial remand after we deny rehearing puts the case in the same posture as if we had initially granted rehearing, subject to any special instructions in the mandate. The remedial action to be taken by us in either event will turn on the equities presented.

Taking such remedial action differs from the ordinary processing of certificate applications. The typical Section 7(c) case involves ultimately the broad question whether the applicant should be permitted to enter the field; review of proposed initial rates is but one facet of our certificate powers. When an applicant first proposes interstate service (and prior to dedication under Section 7(b) of the Act) he is not only entitled to the statutory processes, fairly administered; but he is also privileged to reject, for whatever reasons he wishes, any tendered certificate, no matter how reasonable the terms offered. In these remedial proceedings, we are called upon to exercise only our rate review powers under Section 7; no question arises as to the propriety of allowing the producers to introduce their gas into jurisdictional commerce. Thus nothing imperils the producers' "security of certificate." By the same token, there can be no private option here to accept or reject the results of our initial rate review at the regulated company's whim, any more than a company is free to accept or reject the results of a rate review proceeding under Section 4 or 5 of the Act. Consideration of the three groups of proceedings at issue brings these matters into focus.

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[3] See note 2, on p. 482.

Docket Nos. G–13169 *et al.* were heard and originally decided by us in 1958, prior to the Supreme Court's 1959 decision in *Catco* (360 U.S. 378). The producers accepted the unconditional certificates prior to the expiration of the 30-day period prescribed by Section 19(a) of the Act for seeking rehearing, and commenced deliveries. No producer sought an extension of time in which to accept the certificates. But the record and the briefs show that the producers' price proposals were opposed throughout the 1958 proceedings. Thus the producers have not been "entrapped"; rather, in presenting their cases and commencing deliveries, they took a calculated risk as to the outcome of any review proceedings which might be brought. Such proceeding in fact resulted in the remand. *P.S.C. of New York* v. *F.P.C.*, 361 U.S. 195.

Upon reconsidering the record as a whole (including the record in G–13143 *et al.*, which originally accompanied that in G–13169 *et al.*), we have concluded that our 1958 order was erroneous, that the record does not show the price proposals of the producers to be in the public interest, and that the record shows, rather, that the proposed prices are out of line. Indeed even the lowest prices here proposed (21.4 cents per Mcf) exceed all of the effective rates shown in Exhibit 13 in the original record, save only some of the Duck Lake and Erath Field sales to United Gas Pipe Line Company and United Fuel Gas Company.[4] The examiner believed that our precedents as of that time barred the use of existing prices to test new price proposals. It is notable, however, that he found only four instances in which the Commission "has heretofore issued or had recommended to it the issuance of unconditioned certificates for sales in the southern Louisiana area at prices as high or higher than those involved herein." 20 FPC at 336, note 14. One of these was the proposed *Catco* price which may not, of course, be relied upon. Another involved proposed contractual sales to Texas Eastern Transmission Corporation, which were abrogated before deliveries had commenced (see 21 FPC 860). Thus only two of the instances cited by the examiner may be considered: Three contracts at 21.5 cents per Mcf (including tax; see 19 FPC 618), and eleven contracts at 22.8 cents per Mcf (including tax; see 19 FPC 558). Moreover, the examiner found it beyond dispute that Transco's purchase of gas at the proposed levels would "trigger" favored nations clauses in many existing contracts, and that this "triggering" could result in a $5,000,000 annual increase in cost to the consumer. Our power eventually to test such increases under Section 4 of the Act is not enough, standing alone, to justify the immediate impact of such "triggering" on the price structure.

Docket Nos. G–17336 *et al.* were in hearing at the time of the Supreme Court's *Catco* decision. We issued unconditional certificates on August 10, 1959, largely in reliance upon the Court of Appeals' affirmance of our order in Docket Nos. G–13169 *et al.*, 269 F. 2d 865 (CA3, August 4, 1959), reversed 361 U.S. 195. The P.S.C. of New York actively contested the producer price proposals. The Court of Appeals held the record inadequate to support the initial prices proposed and remanded for further proceedings in which the producers might either augment the record or seek an appropriate price condition. Exhibit No. 32 shows that these proposed prices, too, are out of line.

Docket Nos. G–16540 *et al.* were also in hearing at the time of the Supreme Court's *Catco* decision. In issuing unconditional certificates, on November 17, 1959, we relied heavily on the Court of Appeals' affirmance of our order in Docket Nos. G–13169 *et al.* as reflecting a correct interpretation of *Catco*. 22 FPC 836.

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[4] Even those high rates are shown, with but one exception, as being effective subject to refund under Section 4 of the Act.

When the Supreme Court reversed the Court of Appeals in that proceeding (361 U.S. 195, December 14, 1959), however, we promptly granted the applications for rehearing which had been duly filed under Section 19(a). We granted a number of extensions of time in which to accept the certificates; but deliveries have ultimately commenced. As Exhibits 52 and 53 reveal, these prices too were out of line. Of the orders authorizing other south Louisiana sales, at comparable prices, cited by the examiner (22 FPC at 855, note 21) all have been remanded by the courts (save only one which was not appealed). Patently, our unconditional certificate order was erroneous in law and could not have been sustained on judicial review had we failed to grant rehearing. Having granted rehearing we should voluntarily correct the error just as if the courts had compelled us to do so. See *Ford Motor Co.* v. *N.L.R.B.*, 305 U.S. 364, 375.

The Eastern Seaboard Companies contend we should forthwith redetermine the proceedings in Docket Nos. G–13169 *et al.*[5] on the basis of our recent determinations in the remanded *Catco* case (Opinion No. 351, issued January 22, 1962). Assuming that we have the power to do so, we nonetheless conclude that we should afford the producers further opportunity to be heard. The mandate of the Court of Appeals in Docket Nos. G–17336 *et al.* requires us to afford such opportunity and also, in effect, to receive and allow consideration of such settlement proposals as the producers may now see fit to offer. We think similar opportunities should be afforded the producers in the other proceedings.

On the other hand, many parties argue against leaving the initial price question in these cases to abide the outcome of the Area Rate proceeding. We are anxious to expedite final resolution of proceedings which have already been heard and decided once, but which remain on our docket by virtue of Section 19 of the Act. We are also impressed by representations as to the practical problems posed by the continuing pendency of these proceedings. As several producers observe, the uncertainties as to these initial prices complicate settlements with royalty owners and interfere with prudent budgeting and other financial matters. We are convinced that such uncertainties can quickly be dispelled in these proceedings as a result of the "ground rules," established by our recent *Catco* opinion, for certificate cases originally heard prior to issuance of our General Policy Statement. We shall, therefore, sever these proceedings from Docket No. AR61–2 and prescribe further procedures to achieve that result. These procedures will also be applicable to five additional south Louisiana certificate dockets remanded by the courts (Docket Nos. G–16108, G–16388, G–14753, G–15122 and G–16380).

In Opinion No. 351 (*Continental Oil Co.*, 27 FPC 96, issued January 22, 1962) we determined the proper initial price by considering old and new field prices in the south Louisiana area, as of the year of the sales contract, and excluding the prices which the courts have called into question. We held the proper price line to fall between the highest group of prices and the median price and concluded, on the basis of a comprehensive record, that the "in line" price for 1956 contracts would be not in excess of 18.5 cents per Mcf, where State severance tax did not apply, and 20 cents per Mcf, where such tax applies. It is our present opinion that the "in line" price is also the "public interest" price in these proceedings. The instant proceedings, however, involve contracts executed after 1956; and we recognize that some parties may wish an opportunity to show that the appropriate price line in these proceedings differs from that we determined in *Catco*. Furthermore, we shall not foreclose any party from presenting evidence which he believes would compel the conclusion that a higher price

[5] The Eastern Seaboard Companies are not participants in Docket Nos. G–17336 *et al.*

would be in the public interest. As in *Socony Mobil Oil Company, Inc.*, Docket No. G–13780, we shall require that any such evidence, as well as accompanying argument, be submitted in writing. In view of the large number of proceedings and parties here, however, it is suggested that a pre-hearing conference be convened by a presiding officer of the Commission.

The Commission further finds:

(1) It is reasonable and appropriate to sever and consolidate the above-captioned proceedings, to grant prompt opportunity for further hearing by providing for the submission of written evidence and argument, and to provide supplementary procedures, all as hereinafter prescribed.

(2) The assignments of error and grounds for rehearing set forth in the applications for rehearing cited in note 2, above, set forth no new facts or principles of law which were not fully considered by the Commission in adopting its order of January 10, 1962, in Docket Nos. G–13169 *et al.*, G–17336 *et al.*, and G–16540 *et al.*, or which having now been considered warrant any change or modification except as prescribed below.

The Commission orders:

(A) The proceedings in Docket Nos. G–13169 *et al.*, G–17336 *et al.*, G–16540 *et al.*, G–16108, G–16388 and G–14753 are severed from those in Docket Nos. AR61–2 *et al.*

(B) The proceedings listed in paragraph (A) above, as well as those in Docket Nos. G–15122 and G–16380, are consolidated for the limited purpose of determining the public interest initial price or prices applicable to these proceedings.

(C) On or before April 4, 1962, the participants to these proceedings shall serve and file with the Commission such written testimony, exhibits, and arguments, subscribed and verified by the witness or other person responsible for the preparation of such material, as they deem material to determination of the public interest initial price or prices in these proceeding.

(D) A hearing will be held in these proceedings at 10:00 a.m. (e.s.t.), on April 26, 1962, in a hearing room of the Federal Power Commission, 441 G St. NW., Washington, D.C.

(E) Except as hereinabove granted the applications for rehearing of our order of January 10, 1962, are denied.

APPENDIX I

Docket No.	*Seller*
G–13169	Texaco-Seaboard Inc.
G–13183	Placid Oil Company, Operator, *et al.*
G–13184	Placid Oil Company
G–13197	Frankel, J. R., *et al.*
G–13219	Atlantic Refining Company
G–13231	Pan American Petroleum Corporation
G–13232	Pan American Petroleum Corporation
G–13233	Pan American Petroleum Corporation, Operator, *et al.*
G–13293	The California Company, a division of California Oil Company
G–13356	Amerada Petroleum Corporation
G–13642	Republic Natural Gas Company, Operator, *et al*
G–13710	Sun Oil Company
G–13746	Socony-Mobil Oil Company, Inc.
G–13757	Newmont Oil Company
G–13758	Continental Oil Company
G–13973	Sohio Petroleum Company

G–14109 Hassie Hun[illegible] A, Operator, *et al.*
G–14164 Austral Oil Company, Inc., Operator, Agent for Oil Participations, Inc.
G–14203 Union Oil Company of California
G–14227 Union Texas Natural Gas Corporation Diversa, Inc.
G–14240 Diversa, Inc.
G–14242 Austral Oil Company, Inc., Operator, Agent for Oil Participations, Inc.
G–14243 Austral Oil Company, Inc., Operator, Agent for Oil Participations, Inc.
G–14244 Phillips Petroleum Company
G–14254 Sun Oil Company
G–14256 Humble Oil and Refining Company, Operator, *et al.*
G–14346 The Ohio Oil Company
G–14351 The Pure Oil Company
G–14355 Cities Service Production Company
G–14356 Cities Service Production Company
G–14362 Union Oil Company of California
G–14385 Tidewater Oil Company
G–14604 Humble Oil and Refining Company
G–14605 Humble Oil and Refining Company
G–14606 Humble Oil and Refining Company
G–14607 Humble Oil and Refining Company

APPENDIX II

Docket No.	*Seller*
G–17336	Texas Gas Exploration Corporation, Operator, *et al.*
G–17337	J. Ray McDermott and Company, Inc.
G–17338	Kilroy Properties, Inc., *et al.*
G–17339	The California Company, a division of California Oil Company, Operator, *et al.*
G–17340	Callery Properties, Inc.
G–17341	Callery Properties, Inc.
G–17342	Ocean Drilling and Exploration Company
G–17343	Ocean Drilling and Exploration Company, Operator, *et al.*
G–17391	Humble Oil and Refining Company
G–17393	Amerada Petroleum Corporation
G–17396	Kerr-McGee Oil Industries, Inc.
G–17397	Bel Oil Corporation
G–17398	Sands, Caroline Hunt, *et al.*
G–17399	Sid W. Richardson d/b/a Richardson & Bass, Operator, *et al.*
G–17401	Socony-Mobil Oil Company, Inc.
G–17402	Beck Oil Company
G–17405	Phillips Petroleum Company, *et al.*
G–17407	Amerada Petroleum Corporation
G–17413	Mississippi River Fuel Corporation
G–17457	Union Oil Company of California
G–17463	Tidewater Oil Company
G–17474	Tidewater Oil Company
G–17475	Tidewater Oil Company
G–17483	Tidewater Oil Company
G–17554	Continental Oil Company
G–17560	Shell Oil Company
G–17566	Continental Oil Company
G–17574	Pan American Petroleum Corporation

APPENDIX III

Docket No.	*Seller*
G–16540	Republic Natural Gas Company, *et al.*
G–17381	Kerr-McGee Oil Industries, Inc.
G–17417	Pan American Petroleum Corporation
G–17444	Southern Natural Gas Company—Phillips Petroleum Company, Joint Venture
G–17447	Phillips Petroleum Company

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

HOUSTON TEXAS GAS AND OIL CORPORATION, DOCKET NOS. CP62–106 AND G–18615

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 8, 1962)

On October 23, 1961, Houston Texas Gas and Oil Corporation (Applicant) filed in Docket No. CP62–106 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of certain facilities to enable Applicant to provide interruptible natural gas service to two direct industrial customers, Swift and Company (Swift), near Agricola, Florida, and Armour and Company (Armour), near the City of Fort Meade, Florida.

Applicant has entered into contracts with Armour and Swift, dated September 15, 1961, and April 21, 1961, respectively, providing for the direct sale of maximum annual estimated natural gas volumes of 1,225,000 Mcf per year to Armour and 208,000 Mcf per year to Swift, both on an intermediate interruptible basis. Gas will be sold to both customers at a rate of 35 cents per Mcf.

Applicant also requests that the Commission amend its order issued August 9, 1961, in Docket No. G–18615, as amended, wherein Applicant was authorized, among other things, to construct and operate 12.0 miles of 2-inch lateral transmission pipeline extending from its existing 3-inch line at Agricola, Florida, to Ft. Meade and to sell and deliver natural gas for resale in and around Ft. Meade. Applicant requests authorization to construct and operate 8.78 miles of 2- and 6-inch pipeline betwen Ft. Meade and Agricola in lieu of the 12.0 miles of 2-inch line authorized in the order of August 9, 1961. The proposed amendment requires a relocation of the previously authorized lateral in order to enable Applicant to render the proposed service to the two industrial customers in Docket No. CP62–106.

Armour and Swift will use the natural gas in the production of fertilizer materials.

The total estimated cost of the proposed facilities in both dockets is $220,000 which is $37,200 greater than the estimated cost of the similar facilities authorized in Docket No. G–18615. The increased cost of construction will be financed from a contingency fund.

The additional sales will have no appreciable effect upon Applicant's gas supply.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 26, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application or the motion to amend has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Houston Texas Gas and Oil Corporation, a Delaware corporation having its principal place of business in St. Petersburg, Florida, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of December 28, 1956, in Docket Nos. G–9262, *et al.* (16 FPC 118).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are to be used in the transportation and delivery of natural gas in interstate commerce, subject to the jurisdiction of the Commission and the construction and operation thereof and the transportation and delivery of natural gas by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities and the proposed transportation and delivery of natural gas by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(6) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act, and the public convenience and necessity require that the order of the Commission issued August 9, 1961, as amended, in Docket No. G–18615, be further amended so as to authorize Applicant to construct and operate 8.78 miles of 2- and 6-inch pipeline between Ft. Meade and Agricola, Florida, in lieu of the 12.0 miles of 2-inch line previously authorized in said order of August 9, 1961.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure in Docket No. CP62–106 was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Houston Texas Gas and Oil Corporation,

to construct and operate the proposed facilities and to transport and deliver to Armour and Company and to Swift and Company up to 1,225,000 Mcf and 208,000 Mcf, respectively, of natural gas per year, both on an interruptible basis, as hereinbefore described, all as more fully described in the application in Docket No. CP62–106, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(C) The facilities hereby authorized shall be constructed and placed in actual operation and the transportation and delivery of natural gas shall commence as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 12 months from the date on which this order issues.

(D) The order issued August 9, 1961, as amended, in Docket No. G–18615, be and the same is hereby further amended so as to authorize Applicant to construct and operate 8.78 miles of 2- and 6-inch pipeline between Ft. Meade and Agricola, Florida, in lieu of the 12.0 miles of 2-inch line previously authorized in the order of August 9, 1961. In all other respects said order, as amended, shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

ORDER ESTABLISHING THE NATIONAL POWER SURVEY EXECUTIVE ADVISORY COMMITTEE

(Issued March 8, 1962)*

The Federal Power Commission is directed by Section 202(a) of the Federal Power Act (16 U.S.C. 792–825r) to promote and encourage voluntary interconnection and coordination of the nation's electric power facilities in the interest of economy and conservation, and is authorized by Section 311 of the Act to conduct broad investigations covering all aspects of the entire power industry. In order to accomplish these objectives more effectively, we have concluded that it is in the public interest that a National Power Survey Executive Advisory Committee be, and it hereby is, established.

1. *Purpose.* The Committee shall advise the Commission in planning and carrying out the Commission's proposed national power survey.

2. *Membership of the Committee.* The Committee shall consist of a representative group of members from all segments of the electric power industry to be selected by the Chairman of the Commission.

3. *Organization.* The detailed functions of the National Power Survey Executive Advisory Committee and any other representative committees established to advise the Commission on the survey will be in accordance with Executive Order No. 11007 of February 26, 1962 (27 FR 1875) relating to the Formation and Use of Advisory Committees.

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*Commission determination issued February 26, 1964 continued Committee for additional two years.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

PANHANDLE EASTERN PIPE LINE COMPANY, DOCKET NO. CP60-103; SHELL OIL COMPANY, DOCKET NO. CI60-660; PIONEER PRODUCTION CORPORATION, DOCKET NO. CI60-689; CALVERT PETROLEUM COMPANY, DOCKET NO. CI60-691; ASHLAND OIL & REFINING COMPANY, DOCKET NO. CI60-738; UNION OIL COMPANY OF CALIFORNIA, DOCKET NO. CI60-802; KING-STEVENSON OIL COMPANY, INC., DOCKET NO. CI60-813.

ORDER DENYING APPLICATIONS FOR REHEARING

(Issued March 9, 1962)

Continental Oil Company, successor in interest to Calvert Petroleum Company, and King-Stevenson Oil Company, Inc. have filed applications for rehearing of our Opinion No. 350 issued in these proceedings on January 15, 1962, 27 FPC 35. The applicants, who are independent producers, were issued conditioned certificates by Opinion No. 350 for the sale of natural gas to Panhandle Eastern Pipe Line Company from fields located in Dewey, Major, Woods and Alfalfa Counties, Oklahoma. In their applications for rehearing, they contend that the Commission erred in conditioning the initial contract price of 17 cents per Mcf to the area ceiling level of 15 cents per Mcf, and in conditioning allowance of the take-or-pay and Btu adjustment provisions of the contracts so as to make these provisions subject to the Commission's determinations in the Docket Nos. R-199 and R-200 rule-making proceedings.

The evidence in the record before us does not compel a finding that these producers should be allowed an initial price in excess of the area ceiling of 15 cents per Mcf. Nor is there sufficient evidence to justify a finding that the area boundary should be adjusted to include these fields in the adjoining 17-cent area. On the other hand the evidence supports the established area price ceiling of 15 cents per Mcf as the "in-line" price for the applicants' proposed sales. In these circumstances, the public convenience and necessity clearly require the price condition which we have attached to the certificates issued to these applicants.

However, in an effort to give recognition to the equities of this case, we have permitted the applicants to take advantage of any increase in the area ceiling level which may result from the review of area boundaries now being made by the Commission. As we noted in Opinion No. 350, a change of area boundaries properly calls for consideration of information and data beyond what these producers have been able to adduce, and is best made upon a general review of all relevant factors. Inasmuch as such a review is presently being made, we here decided that these applicants should be permitted to file substitute increased rates if and when, as a result of our study, the area boundary here in question should be changed so as to increase the ceiling price applicable to the fields from which the proposed sales are to be made. We can go no farther than this in giving consideration to the applicants' request for certification of their sales at an initial price in excess of the existing area ceiling of 15 cents per Mcf.

With respect to the conditions which we have attached to allowance of the proposed take-or-pay and Btu adjustment provisions, making these provisions

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subject to the policy determinations in Docket Nos. R–199 and R–200, we would note that there are basic policy considerations involved in the treatment of these issues which affect the broad public interest and go beyond the question of the impact of the proposed take-or-pay and Btu adjustment provisions on Panhandle's customers in this particular case. These considerations are now before us in the rule-making proceedings referred to. In our opinion, the determination of adjustments in price to be required or allowed for deviations from established standards of pipeline quality gas, including Btu heating content, and the determination of what percentage of a pipeline's contracted gas supply must be paid for in the event the pipeline is unable to take all of its contracted supply, are appropriately within the scope of our rule-making procedure; and in the interest of sound regulation, these determinations should be made and promulgated through regulations or policy statements having general applicability. It is not our intention, in passing upon the proposed provisions in the present case, to either prejudge or to grant what may be exceptions to the determinations in the rule-making proceedings; hence, the necessity of either modifying or eliminating these provisions, or of making our allowance of them subject to the determinations in Docket Nos. R–199 and R–200. So as not to deprive the producers of the revenues which they might derive from these provisions pending final decision in Docket Nos. R–199 and R–200, we have chosen to allow the provisions subject to our disposition of the issues in the rule-making proceedings.

The Commission finds:

The assignments of error and grounds for rehearing set forth in the applications for rehearing present no facts or principles of law which were not considered by the Commission when it issued its Opinion No. 350, or which having now been considered warrant any change or modification of the said opinion.

The Commission orders:

The applications for rehearing filed in the above-entitled proceedings are hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr. and Charles R. Ross.

TEXAS EASTERN TRANSMISSION CORPORATION, DOCKET NO. CP62–81; SHELL OIL COMPANY, DOCKET NO. CI62–255; SINCLAIR OIL & GAS COMPANY, DOCKET NOS. CI62–296 AND CI62–297

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 9, 1962)

On September 27, 1961, Texas Eastern Transmission Corporation (Texas Eastern) filed in Docket No. CP62–81 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of approximately 23 miles of 14-inch pipeline, and facilities appurtenant thereto, extending from the Sligo Field, Bossier Parish, Louisiana, to a point of connection with Texas Eastern's existing 24-inch Provident City-Castor pipeline, Red River Parish, Louisiana, to enable Texas Eastern to purchase and receive natural gas produced by Shell Oil Company (Shell) and Sinclair Oil & Gas Company (Sinclair) from the Sligo Field.

On September 5, 1961, in Docket No. CI62–255, and on September 14, 1961, in Docket Nos. CI62–296 and CI62–297, Shell and Sinclair, respectively, filed applications pursuant to Section 7(c) of the Natural Gas Act for certificates of

public convenience and necessity authorizing the sale of natural gas from the Sligo Field to Texas Eastern.

Shell and Sinclair will make the proposed sales pursuant to separate gas contracts with Texas Eastern, each dated July 1, 1961. Shell and Sinclair also propose to sell excess gas from the Sligo Field to Texas Eastern pursuant to separate letter agreements, each dated July 1, 1961; the excess sales are for terms of three years from the date of initial delivery. Shell has applied for authorization for both sales in Docket No. CI62–255; Sinclair has applied in Docket No. CI62–296 for authorization to make the sales under the basic contract, and in Docket No. CI62–297 for authorization to make the excess sales.

Texas Eastern will pay 14.75 cents per Mcf at 15.025 psia for excess gas and 16.4161 cents per Mcf at 15.025 psia for gas purchased under the basic contracts.

The cost of Texas Eastern's project is estimated to be $1,291,000, which cost will be financed from cash on hand or revolving credit with banks.

Texas Eastern in Docket No. CP62–81, Sinclair in Docket Nos. CI62–297 and CI62–296, and Shell in Docket No. CI62–255 were each granted temporary authorization by separate letters, dated November 9, 1961.

Pursuant to due notice a public hearing was held in Washington, D.C., on February 27, 1962, respecting the matters involved in and the issues presented by the applications herein. On February 7, 1962, the Pennsylvania Public Utility Commission filed a notice of intervention in the subject dockets. By letter filed February 23, 1962, the Pennsylvania Commission advised that its intervention was in support of the subject applications. No other petition to intervene or protest to the granting of the applications has been received. No appearances, other than that of staff counsel, were entered at the hearing. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Texas Eastern Transmission Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of October 10, 1947, in Docket No. G–880 (6 FPC 148).

(2) Applicants, Shell Oil Company and Sinclair Oil & Gas Company, independent producers of natural gas, are engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption subject to the jurisdiction of the Commission, and each is, therefore, a "natural-gas company" within the meaning of the Natural Gas Act.

(3) The facilities to be constructed by Texas Eastern, as hereinbefore described and as more fully described in the application in Docket No. CP62–81, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and construction and operation thereof by Texas Eastern are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The sales of natural gas by Shell and Sinclair hereinbefore described, as more fully described in Shell's application in Docket No. CI62–255 and in Sinclair's applications in Docket Nos. CI62–296 and CI62–297, will be made in interstate commerce, subject to the jurisdiction of the Commission and such sales by Shell and Sinclair, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) The sales of natural gas by Shell and Sinclair, together with the construction and operation of any facilities, subject to the jurisdiction of the Commission, necessary therefor, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(6) The construction and operation of the facilities proposed by Texas Eastern in Docket No. CP62–81 are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(7) The respective Applicants are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(8) Public convenience and necessity require that the certificate issued hereinafter to Texas Eastern and the rights granted thereunder be conditioned upon Texas Eastern's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c) (3), (c) (4) and (e) of Section 157.20 of such Regulations.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Texas Eastern Transmission Corporation, to construct and operate the facilities as hereinbefore described, all as more fully described in the application in Docket No. CP62–81, upon the terms and conditions of this order.

(B) A certificate of public convenience and necessity be and the same is hereby issued upon the terms and conditions of this order, authorizing the sale by Shell Oil Company of natural gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission used for the sale of natural gas in interstate commerce, to Texas Eastern, as hereinbefore described and as more fully described in the application in Docket No. CI62–255.

(C) Certificates of public convenience and necessity be and the same are hereby issued upon the terms and conditions of this order, authorizing the sales by Sinclair Oil and Gas Company of natural gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission used for the sales of natural gas in interstate commerce, to Texas Eastern, as hereinbefore described and as more fully described in the applications in Docket Nos. CI62–296 and CI62–297.

(D) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Texas Eastern's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c) (3), (c) (4) and (e) of Section 157.20 of such Regulations.

(E) The time within which the facilities authorized in paragraph (A) above shall be completed and placed in actual operation is hereby fixed at six months from the date on which this order issues.

(F) The certificates hereby issued to Shell in paragraph (B) above and to Sinclair in paragraph (C) above are not transferable and shall be effective only so long as Shell and Sinclair continue the acts or operations hereby authorized

in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations and orders of the Commission.

(G) The grant of the certificates herein to Shell and Sinclair shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or of Section 154 of the Commission's rules and regulations thereunder requiring the filing of rate schedules for the services herein authorized and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceedings now pending or hereafter instituted by, or against, Shell or Sinclair. Further, our action in these proceedings shall not foreclose nor prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contracts herein involved.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr. and Charles R. Ross.

AMERICAN LOUISIANA PIPE LINE COMPANY, DOCKET NO. CP62-141

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 12, 1962)

On December 7, 1961, American Louisiana Pipe Line Company (Applicant) filed in Docket No. CP62-141 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation during the 12-month period commencing March 1, 1962, of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which may be purchased from producers thereof in the general area of its existing transmission system at a total cost not to exceed $3,000,000, with no single project to exceed a cost of $500,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its existing pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

Pursuant to due notice, a public hearing was held in Washington, D.C., on February 27, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, American Louisiana Pipe Line Company, a Delaware corporation having its principal place of business in Detroit, Michigan, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 1, 1954, in Docket No. G-2306, *et al.*, (13 FPC 380).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing pipeline system, and the con-

struction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas purchased from producers thereof during the 12-month period commencing March 1, 1962, as proposed by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit on or before May 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(6) The authorization hereinafter granted should be limited to construction during the 12-month period commencing March 1, 1962, and the total expenditures for facilities to be constructed thereunder should be limited to $3,000,000, with no single project to exceed a cost of $500,000.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing American Louisiana Pipe Line Company to construct during the 12-month period commencing March 1, 1962, the proposed facilities hereinbefore described (more fully described in the application filed in this proceeding) and to operate such facilities only to take natural gas from producers who have received authorization from the Commission to sell natural gas to American Louisiana Pipe Line Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) Applicant shall submit, on or before May 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the

respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the 12-month period commencing March 1, 1962, and the total expenditures for facilities to be constructed hereunder are hereby limited to $3,000,000, with no single project to exceed a cost of $500,000.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr. and Charles R. Ross.

CITIES SERVICE GAS COMPANY, DOCKET NO. G-2214

ORDER AMENDING ORDER ISSUING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 12, 1962)

On October 10, 1961, Cities Service Gas Company (Applicant) filed an application to amend the Commission's order of September 25, 1953, in Docket No. G-2214, issuing a certificate of public convenience and necessity authorizing Applicant to construct and operate certain facilities in Cherokee County, Kansas, and in Jasper County, Missouri, in order to sell and deliver natural gas, on an interruptible basis, to the Missouri Farmers' Association, Inc., now Farmers Chemical Company (Farmers), to be utilized by Farmers at its fertilizer plant near Empire City, Kansas. The subject order limited deliveries of natural gas to 182,077 Mcf* annually.

Applicant states that it has been advised by Farmers that the latter intends to expand its Empire City plant and will require 338,154 Mcf* of natural gas annually. Therefore, Applicant requests in the subject application that the order of September 25, 1953, be amended to allow Applicant to deliver the required increased volumes of gas.

No additional facilities will be required to make the increased deliveries.

Due notice of the filing of the subject application to amend and opportunity for hearing thereon has been given by publication in the Federal Register on January 31, 1962 (27 FR 908). No protest or petition to intervene has been filed in this proceeding.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act, and the public convenience and necessity require that the Commission's order of September 25, 1953, in Docket No. G-2214 be amended as hereinafter ordered.

The Commission orders:

(A) Paragraph (C)(2) of the Commission's order issued September 25, 1953, in Docket No. G-2214, is hereby amended to read as follows:

(2) The facilities authorized by (A) above shall not be utilized for the delivery of volumes of natural gas on an interruptible basis in excess of 338,154 Mcf annually.

(B) In all other respects, said order shall remain unchanged and in full force and effect.

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* At 14.73 psia.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

CONTINENTAL OIL COMPANY, DOCKET NO. G-11024; THE ATLANTIC REFINING COMPANY, DOCKET NO. G-11034; CITIES SERVICE PRODUCTION COMPANY, DOCKET NOS. G-11046, AND G-15330; TIDEWATER OIL COMPANY, DOCKET NO. G-11049

ORDER GRANTING MOTION FOR STAY

(Issued March 12, 1962)

On January 22, 1962, this Commission issued its Opinion No. 351 and order, 27 FPC 96, issuing permanent certificates of public convenience and necessity to the above named natural gas company applicants upon certain conditions, among which were that the base price for natural gas effective under each of the gas sales contracts involved, from the date of initial service thereunder, shall be, until lawfully changed in the manner provided by the Natural Gas Act, 18.5 cents per Mcf at 15.025 psia, subject to certain conditions; that within 60 days of the date upon which the said order becomes effective, the applicants should refund to Tennessee Gas Transmission Company (Tennessee) the purchaser involved herein, with 6 percent interest, a sum equal to the difference in the price charged to and collected from Tennessee and the base price aforementioned, applied to all volumes delivered to Tennessee under said gas sales contracts, from the date of initial delivery to Tennessee until the effective date of said order; and that within 10 days of such refund each of the applicants shall file with the Commission an officially certified statement showing the amount of such refund, its manner of computation, the interest payments related thereto, and a statement from Tennessee acknowledging the receipt of such refund.

On February 12, 1962, the applicants filed a joint and several motion requesting this Commission to stay the requirements of the aforesaid conditions to the certificates granted them until 60 days after final action by the Commission upon their joint application for rehearing of said opinion and order (which application was filed on February 21, 1962) and until after final disposition of any petition for judicial review, if any, of Opinion No. 351 issued January 22, 1962.

Applicants aver that if they should make the refunds to Tennessee required of them by our order, aforementioned, and subsequent thereto said order should be reversed upon judicial review thereof, if any, "considerable injury would be" inflicted upon them, because, Aplicants aver "there is no provision in law by which they could make themselves whole."

On February 20, 1962, Long Island Lighting Company, an intervener herein, filed an answer in opposition to the motion for stay filed by Applicants. Additionally, on February 23, 1962, the Public Service Commission of the State of New York, a party to these proceedings, filed an answer in which it stated that it would have no objection to the granting of a stay pending this Commission's consideration of any timely filed application for rehearing of the aforementioned opinion and order. However, the New York commission does object to any further stay.

We have considered the Applicants' motion for stay, and the answers filed thereto, and find that said motion should be granted in part. We do not believe that the public interest will be adversely affected by deferring the payment of refunds, with interest, we have found to be proper in the order accompanying

Opinion No. 351, for a period of 60 days after our final action upon any application for rehearing or reconsideration of said Opinion and order which may be filed.

The Commission finds:

Good cause exists for granting the joint and several motion for stay of ordering paragraphs (B), (C) and (D) of the order accompanying Opinion No. 351, issued January 22, 1962, herein, for a period of 60 days following the Commission's final action upon any application for rehearing or reconsideration filed herein.

The Commission orders:

The conditions and requirements set forth in ordering paragraphs (B), (C), and (D) of the order accompanying Opinion No. 351, issued January 22, 1962, to and as a part of the permanent certificates of public convenience and necessity issued thereby, and the compliance of each of the Applicants herein, are hereby stayed until 60 days after final action by the Commission upon any application for rehearing filed in these proceedings.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, and Charles R. Ross.

EAST BAY MUNICIPAL UTILITY DISTRICT, PROJECT NO. 2128

ORDER PERMITTING WITHDRAWAL OF APPLICATION FOR LICENSE (MAJOR)

(Issued March 12, 1962)

On August 28, 1957, East Bay Municipal Utility District, (Applicant) of Oakland, California, filed an application for license for proposed major Project No. 2128 to be located on Mokelumne River and South Fork of Mokelumne River, California.

The application proposed construction of three new developments, known as Middle Bar Development with 18,000 kw of capacity, Camanche Development with 6,000 kw, and Railroad Flat Development (no power planned), and redevelopment of applicant's existing Pardee Development which was constructed and operates under Congressional authorization, viz., Act of April 12, 1934 (48 Stat. 642) to include 7,500 kw in new capacity.

Since the application was filed extensive studies by engineers retained by Applicant indicated that Middle Bar and Railroad Flat developments and redevelopment of the Pardee development should be abandoned in favor of an enlarged Camanche development for flood control and water supply for irrigation and domestic uses, but with no provision for power generation. A commissioned staff study of the feasibility of power installation at the enlarged Camanche development supports the conclusion that provision for power generation is not economically justified.

The enlarged Camanche dam and reservoir is to be constructed by Applicant without power facilities but with monetary contribution by the Federal government for flood control pursuant to Section 205 of Public Law 86-645 approved July 14, 1960 (74 Stat. 499). Construction at a later date of the Middle Bar and Railroad Flat developments will not be precluded by the construction of the enlarged Camanche dam and reservoir.

In view of these facts, Applicant, by letter dated December 15, 1961, requested our permission to withdraw its application for license.

The Commission finds:

In the circumstances recited above, it is appropriate to permit the withdrawal of the afore-mentioned application for license.

The Commission orders:

Permission to withdraw the afore-mentioned aplication for license for Project No. 2128 is granted.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

GLACIER ELECTRIC COOPERATIVE, INC., DOCKET NO. E-6446

ORDER AUTHORIZING TRANSMISSION OF ELECTRIC ENERGY TO CANADA AND SUPERSEDING PREVIOUS AUTHORIZATION

(Issued March 12, 1962)

Glacier Electric Cooperative, Inc. (Applicant), a corporation organized under the laws of the State of Montana and doing business in that State, with its principal place of business at Cut Bank, Montana, filed an application, on January 2, 1962, for a supplemental order, pursuant to Section 202(e) of the Federal Power Act, authorizing an increase in the amounts of electric energy which Applicant is presently authorized to transmit from the United States to Canada.

By Commission order issued January 29, 1953, as amended December 2, 1959, in the above-named docket, Applicant was authorized to transmit electric energy from the United States to Canada, as follows:

At Carway, Alberta, Canada, an amount not to exceed 84,000 kilowatt-hours per annum at a maximum transmission rate of 25 kilowatts;

At Del Bonita, Alberta, Canada, an amount not to exceed 36,000 kilowatt-hours per annum at a maximum transmission rate of 15 kilowatts.

Applicant now seeks authorization to transmit electric energy from the United States to Canada in the following amounts and at the following rates of transmission:

At Carway, Alberta, Canada, an amount not to exceed 500,000 kilowatt-hours per annum at a maximum transmission rate of 150 kilowatts;

At Del Bonita, Alberta, Canada, an amount not to exceed 150,000 kilowatt-hours per annum at a maximum transmission rate of 75 kilowatts.

The amounts of electric energy which Applicant proposes to export, like those amounts presently exported pursuant to the afore-mentioned authorization, are to be transmitted to Canada from points within the State of Montana over two single-phase, three-wire electric lines, operating nominally at 120/240 volts, 60 cycles, which are covered by a Presidential Permit signed by the President of the United States on December 12, 1952 and released to Applicant concurrently with the issuance of Commission order issued January 29, 1953 (12 FPC 823), in the above docket.

According to the application, the increased amounts of power and energy will be used by Applicant to meet the expanding electric requirements of its retail customers in Canada.

Written notice of the application has been given to the Board of Railroad Commissioners of the State of Montana and to the Governor of that State. Notice of the application was also published in the Federal Register on February 15, 1962 (27 F.R. 1436), stating that any person desiring to be heard or to make any protest with reference to the application should on or before February 28, 1962 file with the Federal Power Commission, Washington 25, D.C., a petition or protest. No petition or protest or request to be heard in opposition to the granting of the application has been received.

The Commission finds:

The transmission of electric energy from the United States to Canada, as limited herein and as herein after authorized, will not impair the sufficiency of electric supply within the United States and will not impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of the Commission.

The Commission orders:

(A) Applicant is hereby authorized to transmit electric energy from the United States to Canada in accordance with the terms and conditions set forth in the application and subject to the provisions of this order.

(B) The electric energy which Applicant is hereby authorized to transmit from the United States to Canada shall not exceed 500,000 kilowatt-hours per annum at a maximum transmission rate of 150 kilowatts at Carway, Alberta, Canada, and 150,000 kilowatt-hours per annum at a maximum transmission rate of 75 kilowatts at Del Bonita, Alberta, Canada. The energy which Applicant is hereby authorized to export shall be transmitted over the facilities specified in the Presidential Permit signed by the President of the United States on December 12, 1952 and released to Applicant on January 29, 1953, as referred to above.

(C) The authorization herein granted may be modified from time to time or terminated by further order of the Commission, but in no event shall such authorization extend beyond the date of termination or expiration of the Presidential Permit referred to in paragraph (B) above.

(D) Applicant shall conduct all operations pursuant to the authorization herein granted in accordance with the provisions of the Federal Power Act and pertinent rules, regulations or orders issued by the Commission.

(E) Applicant shall install and maintain adequate metering equipment to measure the flow of all electric energy transmitted from the United States to Canada pursuant to the authority herein granted; shall make, keep and preserve full and complete records with respect to the movement of such energy; and shall furnish to the Commission with respect to such transmission of energy, on or before February 15 of each year, reports in triplicate showing the kilowatt-hours delivered at each of the points herein authorized, the maximum kilowatts of transmission, and the consideration received therefor during each month of the preceding calendar year.

(F) This authorization to transmit electric energy from the United States to Canada shall not be transferable or assignable, but in the event of the involuntary transfer of facilities used for such transmission by operation of law (including such transfers to receivers, trustees, or purchasers under foreclosure or judicial sale), shall continue in effect temporarily for a reasonable time thereafter, pending the making of an application for permanent authorization and decision thereon, provided notice is promptly given in writing to the Commission accompanied by a statement that the physical facts relating to sufficiency of supply, rates, and nature of use remain substantially the same as before the transfer.

(G) This authorization shall be without prejudice to the authority of any State, State regulatory commission, or the Dominion of Canada for the exercise of any lawful authority vested in such State, State regulatory commission, or the Dominion of Canada over Applicant.

(H) This authorization is without prejudice to the authority of this Commission, or any other regulatory body, with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission, or any other regulatory body, and nothing herein shall be construed as an acquiescence by this Commission in any estimate or determination of cost or any valuation of property claimed or asserted.

(I) The authorization herein granted shall supersede that heretofore granted by Commission order issued January 29, 1953, as amended December 2, 1959, referred to above.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. CP61–106; PAN AMERICAN PETROLEUM CORPORATION, DOCKET NO. CI62–1034

ORDER TO SHOW CAUSE, DELINEATING ISSUES AND CONSOLIDATING PROCEEDINGS

(Issued March 12, 1962)

By order of April 6, 1961, we reopened the proceeding in Docket No. CP61–106 for the purpose of determining (1) whether the "budget-type" certificate issued to Tennessee Gas Transmission Company by our order of January 6, 1961, in that proceeding covered the construction and operation of certain facilities necessary to connect the so-called Bastian Bay Field reserves to Tennessee's system and (2) the cost of making such reserves available to the Tennessee system. It appears from filings made and evidence adduced by Tennessee that Tennessee acquired control of certain natural gas reserves in the Bastian Bay Field from Pan American Petroleum Corporation. By order of August 25, 1961, we directed Pan American to file with us certain data with respect to its interests in the Bastian Bay Field. Pan American furnished such data on September 12, 1961.

Hearings have commenced in Docket No. CP61–106. Tennessee has adduced its direct evidence regarding the issues posed by our order of April 6, 1961. That testimony awaits cross-examination.

On October 24, 1961, the Consolidated Natural Gas System Companies,[1] interveners, filed a pleading in *Tennessee Gas Transmission Company*, Docket Nos. G–16842 and CP60–94, requesting, in effect, that those proceedings be consolidated for hearing with Docket No. CP61–106. No formal motion for consolidation has actually been filed. Thereafter, the Examiner by notice of October 27, 1961, granted a motion for continuance filed by the Consolidated System companies and recessed the hearing subject to further order of the Commission.

Docket Nos. G–16842 and CP60–94, among others, were consolidated for hearing by notice of January 15, 1962. Those proceedings concern Tennessee applications for certificates authorizing general expansion of Tennessee's facilities and services. We did not consolidate the proceedings in Docket No. CP61–106 with the expansion proceedings because we do not consider such action to be

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[1] East Ohio Gas Company, Hope Natural Gas Company, Lake Shore Pipe Line Co., New York State Natural Gas Corporation, and The Peoples Natural Gas Company.

appropriate in the public interest. Undoubtedly transportation of Bastian Bay gas may be one issue bearing on Tennessee's expansion plans. But the issues posed in Docket No. CP61–106 differ in the main from those in the expansion case and should be separately and expeditiously decided. We shall, however, further clarify the issues so as to minimize overlapping of evidence in the two cases.

The basic purpose of these proceedings in Docket No. CP61–106 is to determine whether Tennessee has and is engaged in acts subject to our jurisdiction, in connection with the Bastian Bay Field, without having obtained such authorization as the Natural Gas Act requires. The record should also show the estimated cost of service for producing Bastian Bay gas and bringing it to Tennessee's main pipeline facilities (i.e., to the so-called "Muskrat" line) so that we may assess the direct impact of the Bastian Bay transaction on Tennessee's subsequent rate proposals. Finally, we wish the record to show, as a basis for comparison, Pan American's investment in the Bastian Bay Field prior to Tennessee's acquisition.

In view of the issues posed in Docket No. CP61–106, the factual background of the proceedings, and the recent examiner's decision on related questions in *Tennessee Gas Transmission Company, et al.*, Docket Nos. G–14562 *et al.* (issued January 8, 1962), it is necessary and appropriate in the public interest and to carry out the provisions of the Natural Gas Act that we promptly determine the extent, if any, of our specific jurisdiction over Pan American in connection with the Bastian Bay Field. To that end it is reasonable that we issue an order to show cause, directed to Pan American in Docket No. CI62–1034 and consolidate such proceeding with Docket No. CP61–106.

The Commission further finds:

(1) Pan American has, pursuant to a lease sale agreement dated July 15, 1960, executed an assignment and conveyance dated as of December 1, 1960, to Tennessee Gas Transmission Company, of certain leasehold interests and facilities in the Bastian Bay Field, Plaquemines Parish, Louisiana.

(2) At the time of said assignment and conveyance Pan American had partially developed its Bastian Bay leaseholds.

(3) Pan American has carved out and retained certain of its original interests in the Bastian Bay Field.

(4) Pursuant to these instruments Tennessee has agreed to pay Pan American, for the interests assigned and conveyed, a price which is directly proportional to, and subject to redetermination based upon, an estimate of the recoverable underground natural gas reserves underlying the leaseholds assigned and conveyed.

(5) Tennessee has paid to Pan American cash and promissory notes totalling $159,463,500 but subject to redetermination and revision, upward or downward, upon the basis of subsequently estimated natural gas reserves.

(6) Pan American has agreed to cover certain costs of operating and further developing the Bastian Bay leaseholds conveyed to Tennessee out of the revenues from interests in petroleum liquids carved out and retained by Pan American.

(7) Tennessee is taking natural gas produced from the conveyed Bastian Bay leaseholds into its pipeline system, transporting such gas in interstate commerce, and selling such gas in interstate commerce for resale; and it appears that Pan American knew or had reason to know before it committed itself to assigning and conveying the leaseholds that Tennessee would so dispose of Bastian Bay gas.

(8) Notwithstanding the nature of these transactions under State contract and property law, Pan American may be engaged in the "sale" of natural gas

produced at the Bastian Bay Field in interstate commerce for resale and subject to the jurisdiction of the Commission, within the meaning of Sections 1, 4 and 7 of the Natural Gas Act, to Tennessee.

(9) It is necessary and appropriate in the public interest that Pan American be ordered to show cause, if any there be, in Docket No. CI62–1034 why it should not be found to be engaged in the sale of natural gas produced at the Bastian Bay Field subject to the jurisdiction of the Commission without having secured authorization or having filed schedules therefor as required by sub-sections 7(c) and 4(c) of the Natural Gas Act.

(10) The proceedings in Docket No. CI62–1034, should be heard on a consolidated record with those in Docket No. CP61–106.

The Commission orders:

(A) Pan American Petroleum Corporation is hereby directed to show cause, if any there be, in Docket No. CI62–1034, why it should not be found to be engaged in the sale of natural gas produced at the Bastian Bay Field, Plaquemines Parish, Louisiana, subject to the jurisdiction of the Commission to Tennessee Gas Transmission without having secured the authorization or having filed the schedules therefor required by sub-section 7(c) and 4(c) of the Natural Gas Act.

(B) Petitions to intervene in Docket No. CI62–1034 may be filed on or before March 26, 1962, *provided, however*, that any party to Docket No. CP61–106 will be deemed an intervenor in Docket No. CI62–1034 without further filing.

(C) The proceedings in Docket No. CI62–1034 are hereby consolidated with those in Docket No. CP61–106.

(D) The Presiding Examiner is hereby authorized and directed to issue notice of the time and place of resumption of hearings.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

UNITED GAS PIPE LINE COMPANY, DOCKET NOS. G–9547, G–10592, G–12801, G–15360, G–18406, RP60–2, AND RP61–18

ORDER APPROVING SETTLEMENT AGREEMENT, PRESCRIBING REFUNDS, AND TERMINATING PROCEEDINGS IN PART

(Issued March 12, 1962)

The above dockets relate to consolidated rate proceedings arising from proposed increases in rates and charges tendered for filing by United Gas Pipe Line Company (United), pursuant to Section 4 of the Natural Gas Act. The period during which the proposed increase in the respective docket has been collected by United, subject to refund of excess charges, if any, is as follows:

Docket No.	Filing date	Effective date of suspended rates	Periods covered
G–9547	Sept. 30, 1955	Apr. 1, 1956	Apr. 1, 1956 through Nov. 15, 1956.
G–10592	May 15, 1956	Nov. 16, 1956	Nov. 16, 1956 through Nov. 30, 1957.
G–12801	May 29, 1957	Dec. 1, 1957	Dec. 1, 1957 through Nov. 30, 1958.
G–15360	May 29, 1958	Dec. 1, 1958	Dec. 1, 1958 through Sept. 30, 1959.
G–18406	Mar. 30, 1959	Oct. 1, 1959	Oct. 1, 1959 through Aug. 12, 1960.
RP60–2	Feb. 11, 1960	Aug. 13, 1960	Aug. 13, 1960 through June 14, 1961.
RP61–18	Jan. 18, 1961	June 15, 1961	June 15, 1961.

The proceedings in the first five of the above-captioned dockets were consolidated for purposes of hearing and decision [1] by order issued June 22, 1961, and pursuant to that order the hearing was convened on July 17, 1961. Those proceedings were further consolidated to include Docket Nos. RP60–2 and RP61–18 by order issued September 12, 1961. Following various hearing sessions and preliminary discussions looking toward settlement, United completed the presentation of its direct case in all dockets on November 28, 1961. Settlement conferences were thereafter held periodically and concluded on February 19, 1962.

The consolidated proceedings were reconvened on February 19, 1962, at which time there was identified and received in evidence as Exhibit No. 33 a document entitled "Stipulation and Agreement dated February 16, 1962" which in addition to the text of the agreement also includes six appendices designated Appendix A, A–1 and B through E. The parties then stated their position respecting the proposed stipulation and agreement on the record.

In accordance with the request of the parties, the presiding examiner on February 20, 1962, certified the entire record in these proceedings to the Commission for its consideration and disposition. That record shows that all the parties present, except Willmut Oil and Gas Company and Laclede Gas Company, expressed unqualified acceptance of the proposed stipulation and agreement. No party to the proceeding objected to the settlement.

Willmut's acceptance was conditioned on the action of the Supreme Court on Willmut's petition for rehearing on denial of certiorari in its proceeding Sup. Ct. No. 506, Oct. Term, 1961. We take note that the Supreme Court on March 5, 1962 denied Willmut's petition for rehearing thereby eliminating the condition to its acceptance of the settlement.

Laclede's qualified acceptance is based on its position as set forth in the record, that the design of United's PL–C rate in Docket No. RP61–18 represents an extremely high and unwarranted "tilt" in the demand charge. Laclede therefore urges that we modify the proposed agreement as follows: "In RP61–18, United's PL–C rate schedule for the Central Zone shall be redesigned to provide a demand charge not more than 50 percent in excess of that resulting from strict application of the Atlantic Seaboard formula or 75 cents per Mcf per month, whichever is greater, for the period from June 15, 1961, forward" (Tr. 611). Laclede also indicates (Tr. 616) that it is not its purpose to "prevent the accomplishment of the overall objective of settling these seven pending cases" and then concludes:

> Accordingly, if the Commission in its wisdom and discretion does not adopt this modification, Laclede will accept the proposed Stipulation and Agreement with the intent of being given an opportunity to raise the question of rate design in a conference following the post-audit provided in the Agreement or in any hearing which may be thereafter scheduled on disputed issues under Docket No. RP61–18.

We have reviewed and considered Laclede's statement and the comments thereon by Mississippi River Fuel Corporation and United in the context of the terms of the proposed settlement. Among other things, that settlement provides for determination on a post-audit basis of the costs of service for the period during which the RP61–18 rates are in effect. The settlement also sets out (Appendices B and C) the manner in which such costs of service will be prepared and specifically states (Article IV, Section 8) that disputed

[1] Prior hearings in Docket Nos. G–9547 and G–10592 resulted in a Commission decision issued January 4, 1961 (25 FPC 26). Upon appeal, that decision was remanded to the Commission. *Willmut Gas and Oil Co.* v. *FPC*, CADC No. 16245, *et al.*, decided January 4, 1962.

issues of the post-audit "including but not limited to the question of rate design if raised by any party" will be resolved either by conference or by formal hearing and decision thereon after such post-audit costs of service have been served upon all the parties.

It is not our purpose at the present time to prejudge the rate design that may be appropriate in Docket No. RP61–18. The degree of "tilt" in United's PL–C and PL–J rates indicated in Laclede's statement is a matter of concern to us. However, the costs relating to that docket are yet to be determined. Under the circumstances, it appears that consideration and ultimate disposition of this issue can, more appropriately, be accomplished at such time that the costs and all other facts relating to this docket are before us. At such time we shall also consider whether it is proper and feasible that the rate design therein determined be applicable from June 15, 1961 or prospectively only. It is our intention that not only shall Laclede have the opportunity to raise the question of rate design in RP61–18 at the appropriate time, but that in accordance with the provisions of the Natural Gas Act the burden of proof shall continue to rest on United with respect to this issue and all other issues raised by any party with respect to the post-audit costs of service.

The proposed stipulation and agreement and appendices thereto in evidence as Exhibit No. 33, is attached hereto as so marked and made a part of this order. In addition to setting out the procedures referred to above, relating to Docket No. RP61–18, which would limit the issues but not, at this time, fully settle that docket, the agreement also provides for complete settlement of the other six dockets captioned above. In settlement of those dockets, United will refund to its customers the principal amount of $29,778,219, plus interest at the rates prescribed by the Commission in each docket, and computed in the manner provided in Article III of the stipulation. The principal amount to be refunded to each customer is set forth in Appendix A and by rate schedules in Appendix A–1 to the agreement. United will also refund to its customers any amounts it receives from its suppliers, listed in Appendix D to the agreement, as a result of Commission action in pending proceedings relating to such suppliers under Sections 4 or 7 of the Natural Gas Act.

Our review of the record and the terms of the agreement indicates that settlement of these proceedings as proposed and set forth in Exhibit No. 33, and subject to the conditions of this order, is appropriate and in the public interest.

The Commission finds:

The settlement of these proceedings upon the basis of the Stipulation and Agreement attached hereto as Exhibit No. 33* and made a part hereof, is reasonable, and proper and in the public interest in carrying out the provisions of the Natural Gas Act, and should be approved and made effective as hereinafter provided and ordered.

The Commission orders:

(A) The settlement of these proceedings upon the basis set forth in the Stipulation and Agreement, attached hereto as Exhibit No. 33 and made a part hereof, is hereby approved and made effective as proposed therein, subject to the terms and conditions hereinafter ordered.

(B) United, within 15 days from the date of issuance of this order, shall refund the sum of $29,778,219 to its customers in the proportionate share shown opposite such customer's name in Appendix A or A–1 to the agreement plus

* Omitted in printing.

applicable interest, computed in accordance with Article III of the agreement.

(C) United shall pass on to its jurisdictional customers in the above-captioned proceedings such refunds including interest as it may receive from its suppliers under Sections 4 and 7 proceedings under the Natural Gas Act in accordance with Article V of Exhibit No. 33 and Appendices D and E thereto attached.

(D) Within twenty (20) days of making a refund in accordance with paragraphs (B) and (C) above, United shall report to the Commission, in writing and under oath, the amount of the refund made to each of the customers, showing separately the amount of principal and interest so paid together with a computation showing the manner in which such refund was determined, and shall serve a copy of the report upon each of the customers receiving a refund. Concurrently therewith, United shall file with respect to such refunds releases from its jurisdictional customers showing receipt of the principal amount and interest in conformity with the settlement agreement and the provisions of this order.

(E) Upon payment of the amounts provided in Article III of the agreement and upon compliance with the terms and conditions of paragraphs (B) and (D) of this order, the proceedings in Docket Nos. G–9547, G–10592, G–12801, G–15360, G–18406, and RP60–2 shall be deemed terminated, subject only to United's obligations under Article V of the agreement and the applicable provisions of this order.

(F) United shall, as soon as practicable, prepare the post-audit costs of service provided for by Article IV of the agreement and in the manner set forth in Appendices B and C. United shall continue to bear the burden of proof on any issue raised by a party in accordance with the terms of the settlement agreement relating to the post-audit determination of just and reasonable rates in Docket No. RP61–18.

(G) This order is without prejudice to any findings or orders which have been or may hereafter be made by the Commission and is without prejudice to any claims or contentions which may be made by the Commission, United or any other affected party hereto, in any other proceeding or proceedings now pending or hereafter instituted by or against United or any other party hereto.

736–330—64——35

Docket No. G-9547, et al. (first six cases only)

Distribution of refunds by dockets, zones and customers

Name of customer	Total	Docket number					
		G-9547	G-10592	G-12801	G-15360	G-18406	RP60-2
Central zone:							
Pipe line:							
Mississippi River Fuel Corporation	$5,541,829	$728,597	$2,291,902	$1,564,197	$277,756	$10,870	$668,507
Southern Natural Gas Company	1,287,038	155,041	527,712	335,256	49,764	1,667	217,598
Texas Eastern Transmission Corp	1,882,019	265,345	734,149	420,987	116,824	4,307	340,407
Texas Gas Transmission Corporation	2,968,352	402,040	1,194,390	801,959	147,862	5,655	416,446
Total pipe line	11,679,238	1,551,023	4,748,153	3,122,399	592,206	22,499	1,642,958
Town border:							
Arkansas Louisiana Gas Company	336,260	43,890	79,077	73,860	72,250	741	66,442
Chatham, Louisiana, Town of	1,506	37	329	366	339	4	431
Co-op Gas Company, Inc	595	42	116	158	148	1	130
Dixie Gas Company	368	32	85	88	73	1	89
English, Max H.[1]	60	2	11	12	18		17
Huntington, Texas, City of	2,362	249	605	640	453	4	411
Kirkpatrick Utility Company	775	50	165	177	183	2	198
Louisiana Gas Service Company [2]	119,747	6,800	26,209	29,703	25,524	310	31,201
Morehouse Natural Gas Company, Inc.[3]	3,276	190	712	783	697	9	885
Mound, Louisiana, Village of	365	34	68	93	55	1	114
Newton, Texas, City of	1,539		84	440	411	5	599
Pineland, Texas, City of	4,163	316	660	855	1,110	11	1,211
Sabine Gas Company	650					22	628
Sabine Gas Company, Inc	6,921	101	1,486	2,097	1,421	19	1,797
Southern Union Gas Company	82,081			6,418	36,298	421	38,944
Southwest Natural Gas Company	28,261	1,493	6,083	6,657	6,480	76	7,472
Tenaha Gas Company	174			4	80	1	89
United Gas Corporation	962,535	68,887	203,092	228,290	229,572	2,593	230,101
Wood, Hugh N	651	28	112	166	148	2	195
Total town border	1,552,289	122,151	318,894	350,807	375,260	4,223	380,954
Total central zone	13,231,527	1,673,174	5,067,047	3,473,206	967,466	26,722	2,023,912
Jackson zone:							
Pipe line:							
Southern Natural Gas Company	2,910,271	378,642	982,560	108,420	512,283	17,609	910,757
Texas Eastern Transmission Corporation	8,535,434	970,121	2,369,752	364,600	1,659,512	55,586	3,115,863
Total pipe line	11,445,705	1,348,763	3,352,312	473,020	2,171,795	73,195	4,026,620

Town Border:							
Abita Springs, Louisiana, Town of	3,073	89	226	505	633	652	968
Atmore, Brewton and Flomaton, Alabama, Cities of	68,184	2,090	5,453	13,028	15,546	11,999	20,068
Bay Minette, Alabama, Town of	85,017	8,830	11,861	16,467	14,984	14,789	18,086
Bay Springs, Mississippi, Town of	9,120	200	673	1,438	1,719	2,002	3,088
Bay St. Louis, Mississippi, City of	22,394	535	1,604	3,861	4,721	4,798	6,875
Canton, Mississippi, City of	47,190	1,081	2,826	6,566	10,508	9,640	16,569
Clarke-Mobile Counties Gas District	261						261
Chickasawhay Natural Gas District	27,835	754	2,224	5,030	5,004	5,817	9,006
Escambia Natural Gas Service Corporation [4]	8,389	289	752	1,601	1,776	1,602	2,369
Fairhope, Alabama, City of	33,977	891	2,315	5,754	6,900	7,288	10,829
Foley, Alabama, The Utilities Board of	19,548		201	3,043	4,031	4,430	7,843
Greensburg, Louisiana, Town of	2,285	46	163	403	491	499	683
Kentwood and Roseland, Louisiana, Towns of	15,579	286	894	2,874	3,516	3,232	4,777
Louisiana Gas Service Company [5]	239,192	11,807	21,018	39,853	49,121	50,030	67,363
Madisonville, Louisiana, Town of	4,263	100	293	702	901	916	1,351
Milton, Florida, Town of	36,510	649	2,199	5,654	7,667	8,492	11,849
Mississippi Valley Gas Company	1,210,716	195,996	100,916	169,296	231,760	194,426	318,322
Mississippi Valley Gas Company (formerly W. P. Bridges)	42	42					
Mobile Gas Service Corporation, Mobile, Alabama	808,417	20,403	41,879	127,132	190,885	153,854	274,264
Mobile County Gas District	24,647			419	4,992	6,478	12,758
Okaloosa County Gas District	118,520	2,234	6,008	14,944	24,413	22,877	48,044
Pascagoula, Mississippi, City of	96,137	1,972	4,377	14,614	22,721	18,618	33,835
Pensacola, Florida, City of	328,972	26,154	14,494	48,290	75,311	58,734	105,989
Picayune, Mississippi, City of	115,847	11,743	13,933	21,572	22,354	20,666	25,579
Port Gibson, Mississippi, Town of	15,040	280	904	2,242	2,876	3,140	5,598
United Gas Corporation	1,202,452	36,417	82,038	196,511	267,887	238,836	380,763
Utilities, Inc., Lucedale, Mississippi [6]	8,202	220	624	1,371	1,648	1,767	2,572
Walthall Natural Gas Company, Inc.	8,258	275	617	1,351	1,724	1,771	2,520
Waveland, Mississippi, Town of	4,426	69	251	730	1,053	951	1,372
Willmut Gas & Oil Company	365,422	30,111	42,445	62,115	68,923	66,467	95,361
Total town border	4,929,915	353,563	361,188	767,366	1,044,065	914,771	1,488,962
Total Jackson zone	16,375,620	1,702,326	3,713,500	1,240,386	3,215,860	987,906	5,515,582
Northwest Mississippi zone:							
Town border:							
United Gas Corporation	171,072		29,858	54,361	15,400	19,266	52,187
Grand total	29,778,219	3,375,500	8,810,405	4,767,953	4,198,726	1,033,954	7,591,681

[1] Successor to W. B. Logan.
[3] Successor to Louisiana Power & Light Company.
[3] Successor to MerRouge Gas Company.
[4] Successor to Harvestors Homes Company and St. Regis Paper Company.
[5] Successor to Louisiana Power & Light Company.
[6] Successor to Gulf South Utilities Company, Inc.

DOCKET NO. G-9547, ET AL.

Distribution of refunds by docket

	Total	G-9547	G-10592	G-12801	G-15360	G-18406	RP60-2
Central rate zone:							
Rate schedule PL-MF:							
Texas Gas Transmission Corporation	$122,612	$8,041	$35,832	$64,157	$5,914	$339	$8,329
Rate schedule PL-C:							
Mississippi River Fuel Corporation	5,541,829	728,597	2,291,902	1,564,197	277,756	10,870	668,507
Southern Natural Gas Company	1,287,038	155,041	527,712	335,256	49,764	1,667	217,598
Texas Eastern Transmission Corporation	1,882,019	265,345	734,149	420,987	116,824	4,307	340,407
Texas Gas Transmission Corporation	2,845,740	393,999	1,158,558	737,802	141,948	5,316	408,117
Total Rate Schedule PL-C	11,556,626	1,542,982	4,712,321	3,058,242	586,292	22,160	1,634,629
Rate schedule DG-C:							
Arkansas-Louisiana Gas Company	243,752	14,135	51,470	58,715	58,339	653	60,440
Southern Union Gas Company	82,081			6,418	36,298	421	38,944
United Gas Corporation	565,025	29,362	115,215	136,027	138,149	1,592	144,680
Total Rate Schedule DG-C	890,858	43,497	166,685	201,160	232,786	2,666	244,064
Rate schedule G-C:							
Arkansas-Louisiana Gas Company	6,888	353	1,402	1,633	1,408	19	2,073
Chatham, Louisiana	1,506	37	329	366	339	4	431
Co-op Gas Company, Inc.	595	42	116	158	148	1	130
Dixie Gas Company	368	32	85	88	73	1	89
English, Max H.[1]	60	2	11	12	18		17
Huntington, Texas, City of	2,362	249	605	640	453	4	411
Kirkpatrick Utility Company	775	50	165	177	183	2	198
Louisiana Gas Service Company [1]	119,747	6,800	26,209	29,703	25,524	310	31,201
Morehouse Natural Gas Company, Inc.[1]	3,276	190	712	783	697	9	885
Mound, Louisiana, Village of	365	34	68	93	55	1	114
Newton, Texas, City of	1,539		84	440	411	5	599
Pineland, Texas, City of	4,163	316	660	855	1,110	11	1,211
Sabine Gas Company	650					22	628
Sabine Gas Company, Inc.	6,921	101	1,486	2,097	1,421	19	1,797
Southwest Natural Gas Company	28,261	1,493	6,083	6,657	6,480	76	7,472
Tenaha Gas Company	174			4	80	1	89
United Gas Corporation	257,620	13,130	52,127	60,789	61,917	706	68,951
Wood, Hugh N	651	28	112	166	148	2	195
Total Rate Schedule G-C	435,921	22,857	90,254	104,661	100,465	1,193	116,491

Rate schedule IND-C:							
Arkansas-Louisiana Gas Company	85,620	29,402	26,205	13,512	12,503	69	3,929
United Gas Corporation	139,890	26,395	35,750	31,474	29,506	295	16,470
Total rate schedule IND-C	225,510	55,797	61,955	44,986	42,009	364	20,399
Total rate schedules DG-C, G-C, IND-C	1,552,289	122,151	318,894	350,807	375,260	4,223	380,954
Total central rate zone	13,231,527	1,673,174	5,067,047	3,473,206	967,466	26,722	2,023,912
Jackson rate zone:							
Rate schedule PL-J:							
Southern Natural Gas Company	2,910,271	378,642	982,560	108,420	512,283	17,609	910,757
Texas Eastern Transmission Corporation	8,535,434	970,121	2,369,752	364,600	1,659,512	55,586	3,115,863
Total rate schedule PL-J	11,445,705	1,348,763	3,352,312	473,020	2,171,795	73,195	4,026,620
Rate schedule DG-J:							
Atmore, Brewton and Flomaton, Alabama	26,726					6,658	20,068
Canton, Mississippi	47,190	1,081	2,826	6,566	10,508	9,640	16,569
Mississippi Valley Gas Company	790,779	19,720	47,149	123,952	191,284	155,883	252,791
Mobile Gas Service Corporation	808,417	20,403	41,879	127,132	190,885	153,854	274,264
Okaloosa County Gas District	116,286		6,008	14,944	24,413	22,877	48,044
Pascagoula, Mississippi	96,137	1,972	4,377	14,614	22,721	18,618	33,835
Pensacola, Florida	309,246	6,428	14,494	48,290	75,311	58,734	105,989
United Gas Corporation	624,125	15,946	35,026	99,971	150,079	117,429	205,674
Willmut Gas & Oil Company	152,595	3,787	8,585	24,027	35,867	29,064	51,265
Total rate schedule DG-J	2,971,501	69,337	160,344	459,496	701,068	572,757	1,008,499
Rate schedule G-J:							
Abita Springs, Louisiana	3,073	89	226	505	633	652	968
Atmore, Brewton and Flomaton, Alabama	41,458	2,090	5,453	13,028	15,546	5,341	
Bay Minette, Alabama	23,053	450	1,173	3,671	4,598	5,366	7,795
Bay Springs, Mississippi	9,120	200	673	1,438	1,719	2,002	3,088
Bay St. Louis, Mississippi	22,394	535	1,604	3,861	4,721	4,798	6,875
Chickasawhay Natural Gas District	27,835	754	2,224	5,030	5,004	5,817	9,006
Clarke-Mobile Counties Gas District	261						261
Escambia Natural Gas Service Corporation [4]	8,389	289	752	1,601	1,776	1,602	2,369
Fairhope, Alabama	33,977	891	2,315	5,754	6,900	7,288	10,829
Foley, Alabama, Utilities Board of	19,548		201	3,043	4,031	4,430	7,843
Greensburg, Louisiana	2,285	46	163	403	491	499	683
Kentwood and Roseland, Louisiana	15,579	286	894	2,874	3,516	3,232	4,777
Louisiana Gas Service Company [3]	205,490	6,286	15,758	34,717	45,004	42,545	61,180
Madisonville, Louisiana	4,263	100	293	702	901	916	1,351
Milton, Florida	36,510	649	2,199	5,654	7,667	8,492	11,849
Mississippi Valley Gas Company	19,621	653	1,491	3,184	3,759	4,181	6,353
Mississippi Valley Gas Co. (W. P. Bridges)	42	42					
Mobile County Gas District	24,647			419	4,992	6,478	12,758
Okaloosa County Gas District	2,234	2,234					
Picayune, Mississippi	35,810	931	2,083	5,624	8,493	7,712	10,967

See footnotes at end of table.

DOCKET No. G-9547, ET AL.—Continued

Distribution of refunds by docket

	Total	G-9547	G-10592	G-12801	G-15360	G-18406	RP60-2
Jackson rate zone—Continued							
Rate schedule G-J—Continued							
Port Gibson, Mississippi	$15,040	$280	$904	$2,242	$2,876	$3,140	$5,598
Utilities, Inc., Lucedale, Mississippi [1]	8,202	220	624	1,371	1,648	1,767	2,572
United Gas Corporation	527,900	15,623	40,147	88,654	108,785	111,066	163,625
Walthall Natural Gas Company, Inc.	8,258	275	617	1,351	1,724	1,771	2,520
Waveland, Mississippi	4,426	69	251	730	1,053	951	1,372
Willmut Gas & Oil Company	69,957	1,776	4,932	11,159	14,660	14,788	22,642
Total rate schedule G-J	1,169,372	34,768	84,977	197,015	250,497	244,834	357,281
Rate Schedule IND-J:							
Bay Minette, Alabama	16,964	8,380	10,688	12,796	10,386	9,423	10,291
Louisiana Gas Service Company [2]	33,702	5,521	5,260	5,136	4,117	7,485	6,183
Mississippi Valley Gas Company	400,316	175,623	52,276	42,160	36,717	34,362	59,178
Pensacola, Florida	19,726	19,726					
Picayune, Mississippi	80,037	10,812	11,850	15,948	13,861	12,954	14,612
United Gas Corporation	50,427	4,848	6,865	7,886	9,023	10,341	11,464
Willmut Gas & Oil Company	142,870	24,548	28,928	26,929	18,396	22,615	21,454
Total Rate Schedule IND-J	789,042	249,458	115,867	110,855	92,500	97,180	123,182
Total Town Border	4,929,915	353,563	361,188	767,366	1,044,065	914,771	1,488,962
Total Jackson Rate Zone	16,375,620	1,702,326	3,713,500	1,240,386	3,215,860	987,966	5,515,582
Northwest Mississippi Rate Zone:							
Rate Schedule DG-NW:							
United Gas Corporation	57,456		12,008	22,063	9,492		13,893
Rate Schedule G-NW:							
United Gas Corporation	113,616		17,850	32,298	5,908	19,266	38,294
Total NW Mississippi Rate Zone	171,072		29,858	54,361	15,400	19,266	52,187
Total Refund	29,778,219	3,375,500	8,810,405	4,767,953	4,198,726	1,033,954	7,591,681

[1] Successor to W. B. Logan.
[2] Successor to Louisiana Power & Light Co.
[3] Successor to Mer Rouge Gas Company.
[4] Successor to Harvesters Homes Company and St. Regis Paper Company.
[5] Successor to Gulf South Utilities Company, Inc.

United Gas Pipe Line Company supplier rates which are subject to possible refund in proceedings under sections 4 and 7 of the Natural Gas Act

Gas supplier (1)	Field (2)	FPC docket No. (3)	Supplier's FPC rate schedule No. (4)	Rates subject to revision (5)	Period covered (6)
SECTION 4					
Alexander, C. W. et al	Maxie-Pistol Ridge	G-10,565	1	20.0¢	Effective Sept. 30, 1957.
Amerada Petroleum Corp.	S. Elton	G-14,421	65	20.25¢	Effective July 16, 1958.
American Petrofina, Inc.	Mustang Island	G-15,009	8	14.80¢	Effective Mar. 20, 1959.
Arkansas Fuel Oil Corp. (now Cities Service Co.)	Bourg	G-12,997	2	20.25¢	Sept. 30, 1957 to June 1, 1961.
		RI-61-262		22.25¢	Effective June 1, 1961.
Arkansas Fuel Oil Corp. (now Cities Service Co.)	Crescent Farms	G-10,036	19	20.25¢	Aug. 8, 1956 to June 1, 1961.
Arkansas Fuel Oil Corp. (now Cities Service Co.)		RI61-263		22.25¢	Effective June 1, 1961.
Arkansas Fuel Oil Corp. (now Cities Service Co.)	Duck Lake	G-8,921	10	14.5¢	Nov. 14, 1955 to Apr. 2, 1956.
		G-9,571		21.2¢	Apr. 2, 1956 to Apr. 1, 1957.
		G-11,289		21.4¢	Apr. 1, 1957 to Apr. 1, 1958.
		G-13,467		22.95¢	Effective Apr. 1, 1958.
Atlantic Refining Co., The	Triple "A"	RI61-127	48	15.0¢	Effective Mar. 20, 1961.
Atlantic Refining Co., The	Mustang Island	G-13,583	49	14.8¢	Effective Apr. 1, 1958.
Bond, Durbin	Maxie-Pistol Ridge	G-20,184	1	24.0¢	Effective Apr. 27, 1960.
Borden, S. P.	Maxie-Pistol Ridge	G-20,191	1	24.0¢	Effective Apr. 26, 1960.
California Company, The	St. Martinville	G-14,313	3	20.0¢	Effective July 1, 1958.
Callery, F. A.	Gibson	G-17,822	16	20.25¢	Effective July 16, 1959.
Callery, Frances A.	Napoleonville	G-16,330	7	20.25¢	Effective Feb. 22, 1959.
Chicago Stock Yards Research Company	Houma	RI61-28	2	23.25¢	Effective Jan. 6, 1961.
Cities Service Co.	Mustang Island	G-13,584	9	14.8¢	Effective Apr. 1, 1958.
Continental Oil Company	Maxie-Pistol Ridge	G-20,197	143	23.0¢	Effective May 2, 1960.
Cocke W. H.	Duck Lake	G-9,570	1	21.95¢	Effective Apr. 1, 1956.
Crow, David, Agent	Maxie-Pistol Ridge	G-20,189	7	24.0¢	Effective Apr. 26, 1960.
Evans, J. P., Jr., et al	Baxterville	RI60-237	2	22.883¢	Effective Sept. 11, 1960.
General American Oil Company of Texas	Crescent Farms	RI61-321	42	22.25¢	Effective June 13, 1961.
General American Oil Company of Texas	Hollywood	RI61-321	42	22.25¢	Effective June 13, 1961.
General American Oil Company of Texas	Valentine	G-19,476	37	20.00¢	Effective Feb. 21, 1960.
Goodrich, R. H.	Duck Lake	G-9,575	1	21.2¢	Apr. 1, 1956 to Sept. 18, 1957.
		G-12,231		21.4¢	Sept. 18, 1957 to Apr. 7, 1958.
		G-13,610		22.35¢	Effective Apr. 7, 1958.
Grigsby, Jack W., et al	Maxie-Pistol Ridge	RI61-96	6	24.0¢	Effective Feb. 26, 1961.
Grigsby, Jack W.	Maxie-Pistol Ridge	RI61-96	7	24.0¢	Effective Feb. 26, 1961.
Gulf Oil Corporation	Mustang Island	G-13,518	23	14.8¢	Effective Apr. 4, 1958.
Gulf Oil Corporation	Baxterville	G-18,107	74	22.883¢	Effective Aug. 30, 1959.
Gulf Oil Corporation	Maxie-Pistol Ridge	G-8,516	77	20.0¢	Apr. 6, 1955 to Nov. 27, 1959.

United Gas Pipe Line Company supplier rates which are subject to possible refund in proceedings under sections 4 and 7 of the Natural Gas Act—Continued

Gas supplier (1)	Field (2)	FPC docket No. (3)	Supplier's FPC rate schedule No. (4)	Rates subject to revision (5)	Period covered (6)
Gulf Oil Corporation	Maxie-Pistol Ridge	G-20,198	92	24.0¢	Effective Apr. 26, 1960.
Gulf Oil Corporation	Abbeville	RI61-40	201	20.25¢	Effective Jan. 29, 1961.
Gulf Oil Corporation	Hayes	G-18,669	161	22.8¢	Effective Nov. 7, 1959.
Gulf Oil Corporation	Maxie-Pistol Ridge	G-20,199	134	24.0¢	Effective Apr. 26, 1960.
Harkins & Company, et al	Cabeza Creek	RI61-69	3	14.5¢	Effective Mar. 1, 1961.
Humble Oil & Refining Co.	Duck Lake	G-9,574	35	21.05¢	Apr. 1, 1956 to Apr. 1, 1957.
		G-11,317		21.25¢	Apr. 1, 1957 to Apr. 3, 1958.
		G-13,609		21.45¢	Apr. 3, 1958 to Nov. 5, 1958.
		G-15,180		22.05¢	Effective Nov. 5, 1958.
Humble Oil & Refining Co.	Baxterville	G-18,670	155	22.883¢	Effective Nov. 7, 1959.
Humble Oil & Refining Co.	Maxie-Pistol Ridge	G-20,086	110	24.0¢	Effective Apr. 24, 1960.
Humble Oil & Refining Co.	Houma	RI61-78	245	23.25¢	Effective Feb. 19, 1961.
Humble Oil & Refining Co.	Weeks Island	RI60-187	235	23.55¢	Effective Aug. 25, 1960.
Hunt Oil Company	Duck Lake	G-9, 568	5	21.2¢	Apr. 1, 1956, to Apr. 1, 1957.
		G-11, 124		21.4¢	Apr. 1, 1957, to Apr. 1, 1958.
		G-13, 468		22.95¢	Effective Apr. 1, 1958.
Hunt, W. H.	West Oretta	G-19, 930	3	18.5¢	Effective Apr. 2, 1960.
Hurt Oil & Gas Corp.	Presque Isle & Houma	RI61-299	3	22.25¢	Effective June 1, 1961.
Jett Drilling Company	Maxie-Pistol Ridge	G-20,081	2	24.0¢	Effective Apr. 24, 1960.
Madole, James, et al	Maxie-Pistol Ridge	G-8,510	1	20.0¢	Apr. 15, 1955, to Apr. 26, 1960.
	Maxie-Pistol Ridge	G-20,196		24.0¢	Effective Apr. 26, 1960.
Mound Company	Baxterville	G-18,773	13	22.883¢	Effective Nov. 28, 1959.
North Central Texas Oil Co.	Baxterville	G-19,026	2	22.883¢	Effective Jan. 6, 1960.
Ohio Oil Company, The	Duck Lake	G-12,037	15	21.4¢	July 25, 1957, to Apr. 1, 1958.
Ohio Oil Company, The	Maxie-Pistol Ridge	G-20,185	16	23.0¢	Effective Apr. 24, 1960.
Pan American Petroleum Corp.	Bourg	RI61-294	227	22.25¢	Effective June 1, 1961.
Pan American Petroleum Corp.	Mustang Island	G-13,677	79	14.8¢	Effective Apr. 15, 1958.
Petroleum, Inc.	Presque Isle & Houma	RI61-295	14	22.25¢	Effective June 1, 1961.
Pioneer Oil & Gas Co.	Maxie-Pistol Ridge	G-20,195	1	24.0¢	Effective Apr. 27, 1960.
Pioneer Oil & Gas Co., Inc.	Maxie-Pistol Ridge	G-20,195	3	24.0¢	Effective Apr. 27, 1960.
Placid Oil Company	Lapeyrouse	G-13,180	7	19.5¢	Effective Feb. 5, 1958.
Prentice, Robert B., et al	Houma	G-19,475	3	23.25¢	Effective Mar. 1, 1960.
Prentice, Robert B., et al	Houma	G-19,475	3	23.25¢	Effective Mar. 1, 1960.
Producing Properties, Inc.	Yanta	RI61-79	51	14.5¢	Effective Feb. 19, 1961.
Ridgway, C. R. & W. B.	Maxie-Pistol Ridge	G-19,932	1	23.0¢	Effective Mar. 10, 1961.
Ridgway Management, Inc.	Maxie-Pistol Ridge	G-20,068	1	23.0¢	Effective Mar. 10, 1961.
Ruffin, J. F., Jr., Trustee	Maxie-Pistol Ridge	G-20,192	1	24.0¢	Effective Apr. 26, 1960.

Samedan Associates, Inc.	Midland	RI61-313	4	22.25¢	Effective June 2, 1961.
Scurlock, E. C., et al	North McFaddin	G-14,621	1	14.713¢	Effective Aug. 25, 1958.
Shell Oil Company	Gibson	G-18,697	202	23.30¢	Effective Nov. 13, 1959.
Shell Oil Company	North McFaddin	G-14,970	127	14.713¢	Effective Oct. 11, 1958.
Shell Oil Company	Mustang Island	G-13-515	11	14.8¢	Effective Apr. 1, 1958.
Shell Oil Company	South Houma	G-18,699	204	23.55¢	Effective Nov. 13, 1959.
Shell Oil Company	West Lake Verret	G-18,697	207	23.55¢	Effective Nov. 13, 1959.
Shell Oil Company	St. Gabriel	G-19,155	211	20.55¢	Effective Jan. 22, 1960.
Shell Oil Company	Turtle Bayou	G-18,699	205	23.55¢	Effective Nov. 13, 1959.
Shell Oil Company	Iowa	G-18,698	203	20.55¢	Effective Nov. 13, 1959.
Shell Oil Company	Roanoke	G-19,155	210	19.05¢	Effective Jan. 22, 1960.
Shell Oil Company	Weeks Island	G-18,697	206	23.55¢	Effective Nov. 13, 1959.
Sinclair Oil & Gas Co., et al	Gibson	RI61-34	100	23.30¢	Effective Jan. 14, 1961.
Sinclair Oil & Gas Co.	Maxie-Pistol Ridge	G-19,929	77	24.0¢	Effective Apr. 24, 1960.
Socony Mobil Oil Co., Inc.	Gibson	RI61-441	258	23.30¢	Effective Oct. 14, 1961.
Socony Mobil Oil Co., Inc.	Iowa	G-15,410	24	20.25¢	Effective Dec. 10, 1958.
Socony Mobil Oil Co., Inc.	Mud Lake	G-15,411	69	20.25¢	Effective Dec. 10, 1958.
Socony Mobil Oil Co., Inc.	Maxie-Pistol Ridge	G-20,079	120	23.0¢	Effective Apr. 24, 1960.
Sun Oil Company	Gibson	G-17,717	63	20.25¢	Mar. 10, 1959 to June 1, 1961.
		RI61-276		22.25¢	Effective June 1, 1961.
Sun Oil Company	Mustang Island	G-13,585	16	14.8¢	Effective Apr. 4, 1958.
Sun Oil Company	Maxie-Pistol Ridge	G-19,909	66	24.0¢	Effective Apr. 24, 1960.
Sun Oil Company	Maxie-Pistol Ridge	G-19,908	77	24.0¢	Effective Apr. 24, 1960.
Sun Oil Company	Cabeza Creek	RI60-420	17	14.5¢	Effective Dec. 1, 1960.
Sunray Mid-Continent Oil Co.	Gibson	G-19,906	186	23.30¢	Effective Mar. 29, 1960.
Sunray Mid-Continent Oil Co.	Mustang Island	G-13,586	45	14.8¢	Effective Apr. 1, 1958.
Sunray Mid-Continent Oil Co.	Maxie-Pistol Ridge	G-20,187	80	23.0¢	Effective Apr. 24, 1960.
Superior Oil Company, The	Baxterville	G-18,694	15	22.883¢	Effective Nov. 13, 1959.
Superior Oil Company, The	Cabeza Creek	RI61-97	6	14.5¢	Effective Mar. 22, 1961.
Tenneco Corporation	Mustang Island	G-19,983	8	14.8¢	Effective Apr. 5, 1960.
Tenneco Corporation	Sibley	G-19,983	7	11.2432¢	Effective Apr. 5, 1960.
Tennessee-Texan Oil Company	Mustang Island	G-13,582	3	14.8¢	Effective Apr. 1, 1958.
Texaco Inc.	Duck Lake	G-9,576	102	21.2¢	Apr. 1, 1956 to Apr. 8, 1957.
Texaco Inc.		G-11,333		21.4¢	Apr. 8, 1957 to Apr. 1, 1958.
		G-13,466		22.95¢	Effective Apr. 1, 1958.
Texaco Inc.	McFaddin	G-15,007	124	14.713¢	Effective Oct. 3, 1958.
Texaco Inc.	Baxterville	G-19,430	101	22.883¢	Effective Feb. 17, 1960.
Texaco Inc.	Maxie-Pistol Ridge	G-20,186	121	24.0¢	Effective Apr. 24, 1960.
Texaco Inc.	Houma	RI61-89	223	23.25¢	Effective Feb. 22, 1961.
Texas Gulf Producing Co.	DeLarge	G-17,884	31	22.05¢	Effective July 26, 1959.
Texas Gulf Producing Co.	Dulac	G-17,884	32	22.05¢	Effective July 28, 1959.
Texas Gulf Producing Co.	Abbeville	G-15,056	30	20.25¢	Effective Dec. 31, 1958.
Tidewater Oil Company	Mustang Island	G-13,513	23	14.8¢	Effective Apr. 16, 1958.
Tidewater Oil Company	Baxterville	G-18,567	36	22.883¢	Effective Nov. 1, 1959.
Tidewater Oil Company	Hollywood-Houma	G-9,932	34	19.5¢	July 3, 1956 to June 1, 1961.
		RI61-297		22.25¢	Effective June 1, 1961.
Tidewater Oil Company	Southeast Houma	RI61-292	66	22.25¢	Effective June 1, 1961.
Tidewater Oil Company	Midland	RI61-292	71	22.25¢	Effective June 1, 1961.
Trahan, J. C., Drilling Contractor, Inc.	Gibson	C161-452	15	20.25¢	Effective Oct. 6, 1960.
Trahan, J. C., Drilling Contractor, Inc.	Gibson	RI61-315	12	22.25¢	Effective June 8, 1961.
Union Oil Company of Calif.	Houma	RI60-450	49	23.25¢	Effective Dec. 2, 1960.
Union Oil Company of Calif.	Gordon	G-19,006	30	20.25¢	Effective Dec. 26, 1959.

United Gas Pipe Line Company supplier rates which are subject to possible refund in proceedings under sections 4 and 7 of the Natural Gas Act—Continued

Gas supplier (1)	Field (2)	FPC docket No. (3)	Supplier's FPC rate schedule No. (4)	Rates subject to revision (5)	Period covered (6)
Union Producing Company	Bay Baptiste	G-13,811	216	18.75¢	Effective May 1, 1958.
	Bourg	G-15,661	218	20.25¢	Effective June 2, 1958.
	DeLarge	G-17,589	228	22.05¢	Effective June 24, 1959.
	Dulac	G-17,589	229	22.05¢	Effective June 24, 1959.
	Gibson	G-20,204	234	23.30¢	Effective May 5, 1960.
	Lirette	G-13,811	215	18.75¢	Effective May 1, 1958.
	Greta-Tom O'Connor	G-13,811	78 and 236	14.00¢	Effective May 1, 1958.
	do	G-14,352	78 and 236	14.50¢	Effective July 2, 1958.
	do	G-17,606	78 and 236	15.00¢	Effective July 1, 1959.
	do	RI60-54	78 and 236	15.50¢	Effective July 2, 1960.
	North McFaddin	G-14,553	95	14.71¢	Effective July 27, 1958.
	do	G-14,553	96	14.71¢	Effective July 27, 1958.
	Baxterville	G-18,689	42	22.883¢	Effective Nov. 12, 1959.
	Maxie-Pistol Ridge	G-13, 811	92	20.00¢	Effective May 1, 1958.
	do	G-20,085	92	23.00¢	Effective Apr. 24, 1960.
	do	G-20,085	222	23.00¢	Effective Apr. 24, 1960.
	Sandy Hook	G-20,431	235	18.00¢	Effective May 31, 1960.
	Soso	G-18,689	209	22.883¢	Effective Nov. 12, 1959.
Whitaker, Douglas	Maxie-Pistol Ridge	G-20,193	3	24.0¢	Effective Apr. 26, 1960.
Mecom, John W	Crescent Farms-Hollywood	G-10,357 [1]	3	17.5¢	Oct. 12, 1956, to Apr. 1, 1960.
General American Oil Company of Texas	do	G-10,357 [1]	42	17.5¢	Apr. 1, 1960, to May 1, 1961.
Texas Gulf Producing Co	North McFaddin	G-14,758 [1]	6	14.6¢	Sept. 10, 1958, to Mar. 1, 1961.
R. H. Goodrich	Duck Lake	G-8977	1	14.5¢	Nov. 7, 1955 to Apr. 1, 1956.
W. H. Cocke	Duck Lake	G-8978	1	14.5¢	Nov. 7, 1955 to Apr. 1, 1956.
Hunt Oil Company	Duck Lake	G-9065	5	14.5¢	Dec. 1, 1955 to Apr. 1, 1956.
Texaco Inc	Duck Lake	G-8969	102	14.5¢	Nov. 1, 1955 to Apr. 1, 1956.
Ohio Oil Company	Duck Lake	G-13465	15	22.95¢	Effective Apr. 1, 1958.
Union Producing Company	Bourg	G-14114	218	20.25¢	Effective June 2, 1958.
Sun Oil Company	East Gibson	G-16410	63	20.25¢	Mar. 10, 1959 to June 1, 1961.
Continental Oil Company	St. Martinville	RI60-165	80	20.3¢	Effective Aug. 3, 1960
	Abbeville		98	20.3¢	
Callery	Gibson	RI61-302	16	22.25¢	Effective June 1, 1961.
Texaco Inc	Gibson	RI61-419	231	23.3¢	Effective Sept. 12, 1961.
Gulf Oil Corporation	Maxie-Pistol Ridge	G-18772	77	21.0¢	Nov. 27, 1959 to Apr. 28, 1960.
J. K. Wright, Jr	Maxie-Pistol Ridge	G-20183	2	23.0¢	Effective Apr. 27, 1960.
David Crow	Maxie-Pistol Ridge	G-20188	4, 5	24.0¢	Effective Apr. 26, 1960.

D. A. Biglane	Maxie-Pistol Ridge	G-20190	1	24.0¢	Effective Apr. 26, 1960.
Pioneer Oil & Gas	Maxie-Pistol Ridge	RI61-51	5	24.0¢	Effective Jan. 18, 1961.
Shoreline Pet	Yanta	RI61-79	21	14.5¢	Effective Feb. 19, 1961.
SECTION 7					
Callery Properties, Inc., et al	Gibson	CI61-1444	6	20.25¢	Effective July 1, 1961.
Mecom, John W	Hollywood	CI61-1230	10	22.25¢	Effective May 18, 1961.
Union Producing Company	Calhoun	G-19209	232	20.25¢	Effective Sept. 3, 1959.
Williams Bros. Co. (Aladdin Exploration Co., Farmout)	Maxie (La.)	CI61-1564	1	20.25¢	Effective May 16, 1961.
Williams Brothers Co	Maxie (La.)	CI61-1042	1	20.25¢	Effective Dec. 1, 1960.
L. L. Robinson, et al	Ada	G-16457	4	20.25¢	Effective Mar. 19, 1959.
The Atlantic Ref. Co	Jeanerrette	G-18399	197	20.8¢	Effective Sept. 7, 1959.
Central Oil Co. (O.E.A.)	Martinville	G-18477	1	21.0¢	Effective Mar. 11, 1960.
The Atlantic Ref. Co	Ada	G-18572	202	20.25¢	Effective July 8, 1959.
Sinclair Oil & Gas	No. Leroy	G-17917	172	22.25¢	Effective Feb. 27, 1960.
Gulf Oil Corporation	Bastian Bay	CI60-43	214	23.25¢	No deliveries yet.
Superior Oil Company	No. Turtle Bay	CI61-1436	102	23.25¢	No deliveries yet.
Texaco Inc	No. Leroy	CI62-16	243	21.25¢	Effective Jan. 5, 1962.
Gulf Oil Corporation	No. Leroy	CI62-62	234	22.25¢	Effective Oct. 1, 1961.
Tidewater Oil Corporation	Bastian Bay	CI60-142	108	23.25¢	No deliveries yet.
Sun Oil Company	Belle Isle	G-15122	114	23.8¢	Effective Feb. 25, 1960.
California Company, The	Bayou Penchant	G-16108	11	23.8¢	Effective Aug. 18, 1959.
Superior Oil Company, The	Bayou Penchant Four Isle Dome Palmetto Bayou	G-16388	89	23.8¢	Effective Aug. 18, 1959.

[1] Pursuant to Commission Order reducing rates, refunds have been received in these Dockets and such amounts will be included in the refunds to be made by United hereunder.

APPENDIX E—TABLE I

Table of percentages for determining the jurisdictional portion of supplier refunds in accordance with Article V of the Stipulation and Agreement

Docket number	Period	Southwest zone	New Orleans zone	Jackson zone	Central zone
G-9547	Apr. 1, 1956 to Nov. 15, 1956	16. 9733531	44. 1466223	68. 2158399	68. 0708925
G-10592	Nov. 16, 1956 to Nov. 30, 1957	15. 2752748	42. 8516299	66. 1831143	66. 9147120
G-12801	Dec. 1, 1957 to Nov. 30, 1958	16. 3959942	42. 4624367	67. 3991374	65. 9799198
G-15360	Dec. 1, 1958 to Sept. 30, 1959	18. 2347012	42. 6923339	66. 5312124	67. 6467456
G-18406	Oct. 1, 1959 to Aug. 12, 1960	20. 4988182	43. 1355608	66. 4894612	68. 3810961
RP60-2	Aug. 13, 1960 to June 14, 1961	21. 0027593	45. 8221431	67. 5155223	72. 3667935

APPENDIX E—TABLE II

Table of Percentages for Distribution of Jurisdictional Portion of Supplier Refunds Among Wholesale Customers in Accordance With Article V of the Stipulation and Agreement

	Percentage
Central Rate Zone:	
Rate Schedule PL–MF:	
Texas Gas Transmission Corporation	.4141297
Rate Schedule PL–C:	
Mississippi River Fuel Corporation	18. 7178758
Southern Natural Gas Company	4. 3470517
Texas Eastern Transmission Corporation	6. 3566375
Texas Gas Transmission Corporation	9. 6116657
Total Rate Schedule PL–C	39. 0332307
Rate Schedule DG–C:	
Arkansas Louisiana Gas Company	.8232877
Southern Union Gas Company	.2772337
United Gas Corporation	1. 9084075
Total Rate Schedule DG–C	3. 0089289
Rate Schedule G–C:	
Arkansas Louisiana Gas Company	.0232647
Chatham, Louisiana	.0050866
Co-op Gas Company, Inc	.0020097
Dixie Gas Company	.0012429
English, Max H.[1]	.0002027
Huntington, Texas, City of	.0079778
Kirkpatrick Utility Company	.0026176
Louisiana Gas Service Company[2]	.4044530
Morehouse Natural Gas Company, Inc.[2]	.0110649
Mound, Louisiana, Village of	.0012328
Newton, Texas, City of	.0051981
Pineland, Texas, City of	.0140608
Sabine Gas Company	.0021954

See footnotes at end of table.

Table of Percentages for Distribution of Jurisdictional Portion of Supplier Refunds Among Wholesale Customers in Accordance With Article V of the Stipulation and Agreement—Continued

	Percentage
Central Rate Zone—Continued	
Rate Schedule G–C—Continued	
Sabine Gas Company, Inc	.0233761
Southwest Natural Gas Company	.0954533
Tenaha Gas Company	.0005877
United Gas Corporation	.8701277
Wood, Hugh N	.0021988
Total Rate Schedule G–C	1.4723506
Rate Schedule IND–C:	
Arkansas Louisiana Gas Company	.2891869
United Gas Corporation	.4724873
Total Rate Schedule IND–C	.7616742
Total Rate Schedules DG–C, G–C, IND–C	5.2429537
Total Central Rate Zone	44.6903141
Jackson Rate Zone:	
Rate Schedule PL–J:	
Southern Natural Gas Company	9.8296232
Texas Eastern Transmission Corporation	28.8289649
Total Rate Schedule PL–J	38.6585881
Rate Schedule DG–J:	
Atmore, Brewton and Flomaton, Alabama	.0902687
Canton, Mississippi	.1593872
Mississippi Valley Gas Company	2.6709058
Mobile Gas Service Corporation	2.7304792
Okaloosa County Gas District	.3927633
Pascagoula, Mississippi	.3247088
Pensacola, Florida	1.0444978
United Gas Corporation	2.1080214
Willmut Gas & Oil Company	.5153992
Total Rate Schedule DG–J	10.0364314
Rate Schedule G–J:	
Abita Springs, Louisiana	.0103792
Atmore, Brewton and Flomaton, Alabama	.1400270
Bay Minette, Alabama	.0778630
Bay Springs, Mississippi	.0308034
Bay St. Louis, Mississippi	.0756371
Chickasawhay Natural Gas District	.0940145
Clarke-Mobile Counties Gas District	.0008815

See footnotes at end of table.

Table of Percentages for Distribution of Jurisdictional Portion of Supplier Refunds Among Wholesale Customers in Accordance With Article V of the Stipulation and Agreement—Continued

	Percentage
Jackson Rate Zone—Continued	
Rate Schedule G–J—Continued	
Escambia Natural Gas Service Corporation [4]	.0283344
Fairhope, Alabama	.1147595
Foley, Alabama, Utilities Board of	.0660246
Greensburg, Louisiana	.0077177
Kentwood and Roseland, Louisiana	.0526190
Louisiana Gas Service Company [2]	.6940554
Madisonville, Louisiana	.0143985
Milton, Florida	.1233148
Mississippi Valley Gas Company	.0662712
Mississippi Valley Gas Company (W. P. Bridges)	.0001419
Mobile County Gas District	.0832468
Oklaoosa County Gas District	.0075455
Picayune, Mississippi	.1209505
Port Gibson, Mississippi	.0507985
Utilities, Inc., Lucedale, Mississippi [5]	.0277028
United Gas Corporation	1.7830154
Walthall Natural Gas Company, Inc	.0278919
Waveland, Mississippi	.0149491
Willmut Gas & Oil Company	.2362842
Total Rate Schedule G–J	3.9496274
Rate Schedule IND–J:	
Bay Minette, Alabama	.2092873
Louisiana Gas Service Company [2]	.1138306
Mississippi Valley Gas Company	1.3520925
Pensacola, Florida	.0666258
Picayune, Mississippi	.2703300
United Gas Corporation	.1703204
Willmut Gas & Oil Company	.4825524
Total Rate Schedule IND–J	2.6650390
Total Town Border	16.6510978
Total Jackson Rate Zone	55.3096859
Total Company (Excluding Northwest Mississippi)	100.0000000

[1] Successor to W. B. Logan.
[2] Successor to Louisiana Power & Light Company.
[3] Successor to Mer Rouge Gas Company.
[4] Successor to Harvesters Homes Company and St. Regis Paper Company.
[5] Successor to Gulf South Utilities Company, Inc.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

COMMUNICATIONS WITH THE COMMISSION, INDIVIDUAL COMMISSIONERS, AND PRESIDING OFFICERS, DOCKET NO. R-175

ORDER TERMINATING PROCEEDING

(Issued March 13, 1962)

On May 22, 1959, the Commission instituted a proceeding on the above subject by the issuance of a notice of proposed rulemaking which was published in the Federal Register on June 3, 1959 (24 F.R. 4523).

In view of our Order No. 244 issued this day in *Ex Parte Communications*, Docket No. R-210, further proceedings herein are unnecessary.

The Commission *orders:*

The proceeding in Docket No. R-175 is hereby terminated.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

EX PARTE COMMUNICATIONS, DOCKET NO. R-210

ORDER NO. 244

AMENDING § 1.4 OF THE RULES OF PRACTICE AND PROCEDURE

(Issued March 13, 1962)*

The Commission desires to take all appropriate measures to assure the public and all interested parties that its proceedings will be conducted in a scrupulously fair and impartial manner. We believe that the rule herein adopted, together with existing provisions of our rules, will serve to make it plain that any instance of possible departure from high standards of ethical conduct will be promptly and carefully examined by the entire Commission.

It appears that the amendment adopted herein pertains to Commission practice and procedure and hence that section 4 of the Administrative Procedure Act is not applicable.

The Commission finds:

(1) The amendment adopted herein is necessary and appropriate for the purposes of administration of the Federal Power and Natural Gas Acts.

(2) Good cause exists that the amendment herein adopted becomes effective forthwith.

The Commission, acting pursuant to the authority granted by the Federal Power Act, as amended, particularly sections 308 and 309 thereof (49 Stat. 858; 16 U.S.C. 825g, 825h) and the Natural Gas Act, as amended, particularly sections 15 and 16 thereof (52 Stat. 829, 830; 15 U.S.C. 717n, 717o) *orders:*

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* Published in Federal Register on March 17, 1962 (27 F.R. 2573).

(A) Section 1.4, Rules of Practice and Procedure, Subchapter A, Chapter I of Title 18 of the Code of Federal Regulations, is amended by adding a new subsection (d) to read as follows:

(d) In order to avoid all possibilities of prejudice, real or apparent, to the public interest and persons involved in administrative proceedings pending before this Commission, it is hereby provided: In a contested proceeding, no party thereto, or his counsel, agent, or other person acting on his behalf, shall communicate, *ex parte*, with any member of the Commission or of his personal staff, with the hearing examiner, or with any employee responsible for aiding the Commission in the preparation of a decision in such proceeding, with respect to the merits of that or a factually related proceeding. If a communication of this kind is received, the person (or persons) to whom the representations have been made shall promptly and fully inform the Commission of the substance of the communication and the circumstances thereof, so that the Commission will be enabled to take appropriate action.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

GEORGIA POWER COMPANY, PROJECT NO. 1218

ORDER APPROVING REVISED PROJECT EXHIBIT

(Issued March 13, 1962)

Application was filed on December 22, 1961, by Georgia Power Company, licensee for major Project No. 1218, for Commission approval of revised Exhibit K to show proposed modification of the project boundary by the removal therefrom of three parcels of land containing 10.83 acres, 20.07 acres, and 14.58 acres, respectively.

The licensee desires to utilize a portion of the three parcels in the general operation of its utility business. The parcels will not be used for project purposes. The three parcels are privately-owned land.

The Commission finds:

The following described revised Exhibit K conforms to the Commission's rules and regulations and should be approved as part of the license for the project and Exhibit K (FPC No. 1218–1) which is superseded and which is now part of the license should be eliminated therefrom—all as hereinafter provided:

Revised Exhibit K (FPC No. 1218–9) entitled "Flint River Development Near Albany, Ga., Project Area Map" signed Georgia Power Company, F. E. Shumate, Vice President, July 15, 1932, with revisions as of September 25, 1935, and December 14, 1961.

The Commission orders:

The revised Exhibit K described in the above filing as conforming to the Commission's rules and regulations is approved as part of the license for Project No. 1218, and the exhibit described in the same finding as being superseded is eliminated from the license for the project.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr. and Charles R. Ross.

NONACCEPTABILITY OF RATE FILINGS BASED ON STATE-PRESCRIBED MINIMUM PRICES, DOCKET NO. R-168

ORDER AMENDING ORDER TERMINATING PROCEEDING

(Issued March 14, 1962)*

In our order of February 7, 1962, 27 FPC 326, terminating the above proceeding, the following sentence appears:

> We recognize, moreover, that a buyer of natural gas who has paid seller on the basis of a state minimum price law has an adequate remedy in an appropriate court in the event that his contract entitles him to a refund as a result of the invalidity of the state minimum price laws.[1]

That sentence was not intended to express or imply any view as to whether contract actions in appropriate state or federal courts might be subject to defenses other than defenses based on the Kansas minimum-rate order itself. To avoid doubt on that score, we hereby amend the above-quoted sentence to read as follows:

> We recognize, moreover, that a buyer of natural gas who has paid seller on the basis of a state minimum price law can invoke the jurisdiction of an appropriate court in the event that his contract provides for a refund if the state minimum price laws are held invalid.[2]

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

ATLANTIC SEABOARD CORPORATION, DOCKET NO. CP62-43

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 19, 1962)

On August 22, 1961, as supplemented on October 17, 1961, Atlantic Seaboard Corporation (Applicant) filed in Docket No. CP62-43 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing (1) the construction and operation of approximately 40.3 miles of 30-inch gas transmission pipeline extending in a northeasterly direction from Applicant's 26-inch pipelines at Leesburg Gate, Loudon County, Virginia, to a point of interconnection with Applicant's 20-inch and 26-inch pipelines at Linden Church, Howard County, Maryland, and (2) the installation and operation

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* Published in Federal Register on March 21, 1962 (27 F.R. 2657).

[1] *Pan American Petroleum Corp.* v. *Superior Court of Delaware for New Castle County et al.*, 366 U.S. 656 (1961).

[2] *Pan American Petroleum Corp.* v. *Superior Court of Delaware for New Castle County et al.*, 366 U.S. 656 (1961).

of 1320 additional compressor horsepower at Applicant's Lost River Compressor Station, Hardy County, West Virginia, by turbocharging of six existing compressor units from 1100 h.p. to 1320 h.p. each, all as more fully set forth in the application, as supplemented.

The estimated peak day gas requirements of Applicant's customers for the 1962-1963 winter season will increase approximately 45,800 Mcf over and above the estimated peak day gas requirements for the 1961–1962 winter season. Applicant's existing transmission system does not have sufficient capacity to meet such increased gas requirements. Applicant estimates its customer requirements for the next three years as follows:

	1962–63	*1963–64*	*1964–65*
Peak Day (MMcf)	1,001	1,020	1,068
Annual (MMcf)	192,138	200,818	210,251

The proposed pipeline is also necessary to permit Applicant to obviate additional pipeline operations in the heavily populated urban areas surrounding Washington, D.C., by routing it to avoid such areas. Applicant anticipates that the construction of the proposed pipeline will make unnecessary further pipeline construction in these areas for several years.

The estimated costs of the proposed projects are $5,111,000 for the pipeline and $365,000 for turbocharging compressors. The total cost of $5,476,000 will be financed by the Columbia Gas System, Inc., Applicant's parent.

Applicant does not propose to increase its present contract demand from United Fuel Gas Company, its principal source of supply.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 12, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, herein. No protest to the granting of the application has been received. A petition to intervene was filed on January 22, 1962, by Harold A. Knapp, Jr., of Germantown, Maryland,[1] and was denied by the Commission in its order issued February 19, 1962. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Atlantic Seaboard Corporation, a Delaware Corporation having its principal place of business in Charleston, West Virginia, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 29, 1955, in Docket No. G–6500 (14 FPC 692).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsection (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

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[1] Applicant filed its Answer and Objection to the Petition to Intervene on January 30, 1962.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(6) The time within which the construction of the facilities hereinafter authorized should be completed and said facilities placed in actual operation should be fixed at 12 months from the date of which this order issues.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Atlantic Seaboard Corporation, to construct and operate the proposed facilities, as hereinbefore described, all as more fully described in the application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The facilities authorized by paragraph (A) above shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 12 months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY, DOCKET NO. CP62-105

FINDINGS AND ORDER DIRECTING PHYSICAL CONNECTION OF FACILITIES AND SALE OF NATURAL GAS

(Issued March 19, 1962)

On October 23, 1961, Central Illinois Public Service Company (Applicant) filed in Docket No. CP62-105 an application pursuant to Section 7(a) of the Natural Gas Act for an order directing Natural Gas Pipeline Company of America (Natural) to establish physical connection of its facilities with those which Applicant proposes to construct, and to sell and deliver natural gas to Applicant for resale and distribution in the City of Windsor, Shelby County, Illinois, and environs, all as more fully set forth in the application.

Applicant proposes to construct and operate approximately 4 miles of 4-inch lateral pipeline extending from Natural's existing transmission line to the City of Windsor, and the necessary distribution facilities in the area to be served.

Applicant's estimated gas requirements under this application are as follows:

Year	Requirements in Mcf	
	Peak Day	Annual
1	512	53, 300
2	656	67, 700
3	720	74, 100

The gas will be used for residential and commercial purposes.

On November 3, 1961 Natural advised the Commission that it has no objection to rendering proposed service to the Applicant and that it has the capacity and pipeline facilities to do so. In view of the relatively small volumes of gas involved, there should be no adverse effect on Natural's existing customers.

The estimated cost of Applicant's facilities to receive natural gas and to render the proposed service is $160,200 which will be defrayed from internal funds.

Due notice of the filing of the application and opportunity for hearing thereon has been given by publication in the Federal Register on December 22, 1961 (26 FR 12262). No protest or petition to intervene has been filed in this proceeding.

The Commission finds:

(1) Natural Gas Pipeline Company of America, a Delaware corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of October 13, 1942, in Docket No. G–235 (3 FPC 830).

(2) Applicant, Central Illinois Public Service Company, an Illinois corporation having its principal place of business in Quincy, Illinois, is duly authorized to sell and distribute natural gas in the State of Illinois, and holds a certificate from the Illinois Commerce Commission and a franchise from the City of Windsor authorizing the service proposed.

(3) It is necessary and desirable in the public interest to direct Natural Gas Pipeline Company of America to establish physical connection of its transmission system with the facilities proposed to be constructed and operated by the Applicant and to sell and deliver up to 720 Mcf per day of natural gas to Applicant for resale and distribution in the City of Windsor, Illinois, and environs, under Natural's appropriate rate schedules on file with the Commission.

(4) The requirement that Natural serve Applicant as proposed will not place an undue burden upon Natural nor impair its ability to render adequate service to its existing customers.

The Commission orders:

(A) Natural Gas Pipeline Company of America be and it is hereby directed to establish physical connection of its transmission facilities with the facilities of Applicant proposed under this application, together with such metering, regulating and appurtenant facilities as may be required therefor, and to deliver and sell up to 720 Mcf per day of natural gas to Applicant for resale and distribution in the City of Windsor, Illinois, and environs, under Natural's appropriate rate schedules on file with the Commission, providing Applicant commences the purchase of such natural gas within one year from the date of issuance of this order.

(B) Natural shall report to the Commission in writing and under oath the date of commencement of service to Applicant under this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NO. CP62-63; NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP62-66

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 19, 1962)

On September 14, 1961, as supplemented on October 26, 1961, El Paso Natural Gas Company (El Paso) filed in Docket No. CP62-63, and on September 14, 1961, as supplemented on October 30, 1961, Northern Natural Gas Company (Northern) filed in Docket No. CP62-66, applications pursuant to Section 7(c) of the Natural Gas Act for certificates of public convenience and necessity authorizing the exchange, on a best efforts basis, of 30,000 Mcf of natural gas per day during the period from November 1, 1961, through December 31, 1962.

The applications show that the proposed exchange will be accomplished by use of existing facilities and without charge or payment by either applicant.

Northern and El Paso presently are authorized to exchange up to 475,000 Mcf of natural gas per day at certain interconnections in Oklahoma and Texas and at certain delivery points along El Paso's Plains-Dumas transmission pipeline whereby El Paso makes certain deliveries for the account of Northern. Under the subject proposed exchange, Northern will deliver additional exchange gas to El Paso at the latter's Plains Compressor Station, Yoakum County, Texas, and El Paso will deliver equivalent volumes of additional exchange gas to Northern at El Paso's Dumas Station, Moore County, Texas.

Northern states that in the past it has had approximately 15 billion cubic feet of allowables cancelled by the New Mexico Oil Conservation Commission in Lea County, New Mexico. Northern states further that it is currently in an underproduced position in Lea County and is faced with further cancellation, and that cancellation of allowables will be reduced to the extent that volumes of gas are delivered to El Paso under the subject proposed exchange arrangement.

The proposed exchange will be made pursuant to an agreement between the two Applicants, dated October 20, 1961.

El Paso and Northern were each granted temporary authorization in the subject dockets by separate letters dated December 5, 1961.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 12, 1962, respecting the matters involved in and the issues presented by the applications, as supplemented, herein. No petition to intervene or protest to the granting of the applications has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, El Paso Natural Gas Company, a Delaware corporation having its principal place of business in El Paso, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order issued January 11, 1944, in Docket No. G-288 (4 FPC 486).

(2) Applicant, Northern Natural Gas Company, a Delaware corporation having its principal place of business in Omaha, Nebraska, is a "natural-gas

company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G–280 (3 FPC 967).

(3) The proposed exchange and delivery of natural gas hereinbefore described, as more fully described in the applications, as supplemented, in these proceedings, are to be made in interstate commerce subject to the jurisdiction of the Commission and are, therefore, subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) Applicants are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(5) The proposed exchange and delivery of natural gas by Applicants are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(6) Public convenience and necessity require that the certificates issued hereinafter and the rights granted thereunder be conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (c)(3) and (e) of Section 157.20 of such Regulations.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Certificates of public convenience and necessity be and the same are hereby issued authorizing Applicants, El Paso Natural Gas Company and Northern Natural Gas Company, to exchange and deliver up to 30,000 Mcf of natural gas per day for the period ending December 31, 1962, as hereinbefore described, all as more fully described in the respective applications, as supplemented, in Docket Nos. CP62–63 and CP62–66, upon the terms and conditions of this order.

(B) The certificates issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (c)(3) and (e) of Section 157.20 of such Regulations.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NORTH CENTRAL GAS COMPANY, DOCKET NO. CP62–38; KANSAS-NEBRASKA NATURAL GAS COMPANY, INC., DOCKET NO. CP62–39; TOWER OIL AND GAS COMPANY OF TEXAS, DOCKET NO. CI62–193

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 19, 1962)

On August 17, 1961, as supplemented on October 25, 1961, North Central Gas Company (North Central) filed in Docket No. CP62–38 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of a meter station on its 12-inch pipeline near Orin, Platte County, Wyoming, in order to enable North Central to receive natural gas from Tower Oil and Gas Company of Texas

(Tower), and authorizing the exchange of natural gas with Kansas-Nebraska Natural Gas Company (Kansas-Nebraska) at an existing point of interconnection [1] near the Huntsman Field, Cheyenne County, Nebraska.

On August 17, 1961, Kansas-Nebraska filed in Docket No. CP62–39 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the aforementioned exchange of natural gas near the Huntsman Field, Cheyenne County, Nebraska.

North Central and Kansas-Nebraska have entered into a contract, dated June 20, 1961, with Tower under which each would purchase from Tower in the ratio of 50 percent of available gas produced by Tower in the Shawnee area, Converse County, Wyoming. Since Kansas-Nebraska has no transmission facilities in the Shawnee area, and in order to eliminate the necessity of Kansas-Nebraska constructing duplicate facilities, North Central proposes to receive and transport all gas purchased by both companies from Tower with equivalent volumes due Kansas-Nebraska being delivered to it by North Central from the latter's Huntsman reserves in Nebraska. The subject exchange will be made pursuant to an agreement, dated June 20, 1961, between North Central and Kansas-Nebraska.

The subject sale of gas will be made at a rate of 12 cents Mcf at 15.025 psia.

On August 15, 1961, Tower filed in Docket No. CI62–193 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the above described sale of natural gas to North Central and Kansas-Nebraska.

The Applicants in these proceedings indicate that the proposed sale and the proposed exchange of natural gas may be an interim arrangement and that in the event Tower has under control in the Shawnee area prior to April 1, 1964, reserves of 146 billion cubic feet of gas and sufficient capacity to deliver a maximum of 30,000 Mcf per day, then the gas sales contract between the three Applicants and the exchange agreement between North Central and Kansas-Nebraska will terminate. In the event the foregoing contracts are terminated, the Applicants indicate further that Intermountain Gas Company (Intermountain) has agreed to construct and operate a pipeline from the Shawnee area to Mitchell, Nebraska, and sell gas purchased from Tower to Kansas-Nebraska and North Central; North Central would deliver Kansas-Nebraska's share of this gas at a point near Scottsbluff, Nebraska. However, none of the Applicants in these proceedings is seeking authorization, herein, with respect to the alternate arrangements or proposals. Such information has been included in order to demonstrate the possibilities of the development of the Shawnee area. Therefore, any authorizations hereinafter granted to North Central, Kansas-Nebraska or Tower do not imply approval of any alternate arrangements or proposals, including any contemplated project of Intermountain or any exchange of gas related to that project. Furthermore, any authorization hereinafter granted to Tower does not imply approval of any limited term sales of natural gas in these proceedings by Tower to North Central and Kansas-Nebraska in contemplation of the above-stated alternate project.

The estimated cost of North Central's proposed facilities in Docket No. CP62–38 is $2,112, which cost will be financed out of current working funds.

North Central, Kansas-Nebraska and Tower were each granted temporary authorization by separate letters, dated November 14, 1961.

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[1] Said facilities were modified under temporary authorization granted to Kansas-Nebraska on November 30, 1959, in Docket No. G–17303.

Pursuant to due notice, a public hearing was held in Washington, D. C., on March 8, 1962, respecting the matters involved in and the issues presented by the applications herein. No petition to intervene or protest to the granting of the applications has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, North Central Gas Company, a Wyoming corporation having its principal place of business in Casper, Wyoming, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of February 23, 1943, in Docket No. G–380 (3 FPC 925).

(2) Applicant, Kansas-Nebraska Natural Gas Company, Inc., a Kansas corporation having its principal place of business in Phillipsburg, Phillips County, Kansas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G–259 (3 FPC 966).

(3) Applicant, Tower Oil and Gas Company of Texas, an independent producer of natural gas, is engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption subject to the jurisdiction of the Commission, and is, therefore, a "natural-gas company" within the meaning of the Natural Gas Act.

(4) The facilities to be constructed by North Central, as hereinbefore described and as more fully described in the application in Docket No. CP62–38, are proposed to be used in the transportation of natural gas in interstate commerce, and the proposed exchange and delivery of natural gas by North Central and Kansas-Nebraska, as hereinbefore described and as more fully described in the applications in Docket Nos. CP62–38 and CP62–39, are to be made in interstate commerce, all subject to the jurisdiction of the Commission, and the construction and operation of the subject facilities by North Central and the proposed exchange and delivery of natural gas by North Central and Kansas-Nebraska are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) The sales of natural gas by Tower hereinbefore described, as more fully described in Tower's application in Docket No. CI62–193, will be made in interstate commerce, subject to the jurisdiction of the Commission and such sales by Tower, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therfor, are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(6) The sales of natural gas by Tower, together with the construction and operation of any facilities, subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(7) The construction and operation of the facilities proposed by North Central in Docket No. CP62–38, and the exchange and delivery of natural gas proposed by North Central and Kansas-Nebraska in Docket Nos. CP62–38 and CP62–39, respectively, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(8) The respective Applicants are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(9) Public convenience and necessity require that the certificate issued hereinafter to North Central in Docket No. CP62–38 and the rights granted thereunder be conditioned upon North Central's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(10) Public convenience and necessity require that the certificate issued hereinafter to Kansas-Nebraska in Docket No. CP62–39 and the rights granted thereunder be conditioned upon Kansas-Nebraska's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b) and (e) of Section 157.20 of such Regulations.

(11) The certificates hereinafter issued to North Central, Kansas-Nebraska and Tower should be conditioned upon final approval of the temporarily authorized exchange facilities involved in pending Docket No. G–17303.

(12) The certificate hereinafter issued to Tower should not imply approval of any limited term sales of natural gas in these proceedings by Tower to North Central and Kansas-Nebraska.

(13) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, North Central Gas Company, to construct and operate facilities and to exchange and deliver natural gas all as hereinbefore described, all as more fully described in the application, as supplemented, in Docket No. CP62–38, upon the terms and conditions of this order.

(B) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Kansas-Nebraska Natural Gas Company, Inc., to exchange and deliver natural gas as hereinbefore described, all as more fully described in the application in Docket No. CP62–39, upon the terms and conditions of this order.

(C) A certificate of public convenience and necessity be and the same is hereby issued upon the terms and conditions of this order, authorizing the sale by Tower Oil and Gas Company of Texas of natural gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission used for the sale of natural gas in interstate commerce, to North Central and Kansas-Nebraska, as hereinbefore described and as more fully described in the application in Docket No. CI62–193.

(D) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon North Central's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(E) The certificate issued by paragraph (B) above and the rights granted thereunder are conditioned upon Kansas-Nebraska's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b) and (e) of Section 157.20 of such Regulations.

(F) The exchange and delivery of natural gas authorized in paragraphs (A) and (B) above shall commence within three months from the date on which this order issues.

(G) The certificates issued in paragraphs (A), (B), and (C) above to North Central, Kansas-Nebraska and Tower, respectively, are hereby conditioned upon final approval of the temporarily authorized exchange facilities involved in pending Docket No. G–17303.

(H) The certificate issued in paragraph (C) above to Tower does not imply approval of any limited term sales of natural gas in these proceedings by Tower to North Central and Kansas-Nebraska.

(I) The certificate hereby issued to Tower in paragraph (C) above is not transferable and shall be effective only so long as Tower continues the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations and orders of the Commission.

(J) The grant of the certificate herein to Tower shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or of Section 154 of the Commission's rules and regulations thereunder requiring the filing of rate schedules for the services herein authorized and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by, or against, Tower. Further, our action in these proceedings shall not foreclose nor prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contract herein involved.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

THE OHIO FUEL GAS COMPANY, DOCKET NO. CP62–2; TEXAS EASTERN TRANSMISSION CORPORATION, DOCKET NO. CP62–3

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 19, 1962)

The Ohio Fuel Gas Company (Ohio Fuel), an Ohio Corporation having its principal place of business in Columbus, Ohio, filed on July 6, 1961, an application in Docket No. CP62–2, and on August 3, 1961, a supplement thereto, pursuant to Section 7 of the Natural Gas Act, for a certificate of public convenience and necessity authorizing the establishment of an additional point of delivery and sale to The Dayton Power and Light Company (Dayton) in Madison Township, Fayette County, Ohio, to deliver natural gas to Dayton for resale in Dayton's prospective new market area of New Holland and Waterloo, Ohio, and vicinity. Said additional point of delivery and sale is identical with the point of delivery to Ohio Fuel proposed by Texas Eastern Transmission Corporation (Texas Eastern) in its companion application in Docket No. CP62–3 hereinafter described.

Additional facilities required will include a tap on Texas Eastern's main line facilities, together with necessary measuring and regulating equipment and other appurtenances required for practical operation. The cost is estimated at $26,300. Construction of required facilities will be undertaken by Texas Eastern and, excluding the estimated cost of the main line tap of $800, Ohio Fuel will reimburse Texas Eastern for the cost of the measuring and regulating facilities and assume ownership thereof.

Ohio Fuel estimates, from information received from Dayton, that the combined total natural gas requirements of New Holland and Waterloo will be as follows:

Year	Mcf at 14.73 psia	
	Peak day	Annual
1	325	34,649
2	509	56,221
3	666	77,123

Texas Eastern Transmission Corporation, a Delaware corporation with its principal office in Shreveport, Louisiana, filed on July 6, 1961, an application in Docket No. CP62–3, pursuant to Section 7 of the Natural Gas Act, for a certificate of public convenience and necessity authorizing it to construct and operate a metering and regulating station together with the appurtenant facilities at a point on its main transmission line in Fayette County, Ohio, approximately 5 miles west of Texas Eastern's Compressor Station No. 17. The establishment of this additional delivery point, Texas Eastern shows, is for the purpose of making deliveries of natural gas to The Dayton Power and Light Company for the account of Ohio Fuel in order to permit Dayton to provide service to New Holland and Waterloo, Ohio.

Texas Eastern shows that it is presently authorized to sell and deliver to The Ohio Fuel Gas Company and The Manufacturers Light and Heat Company, jointly, up to 385,400 Mcf (at 15.025 psia) of natural gas per day on a long term basis under Texas Eastern's rate schedules DCQ–C and DCQ–D. Ohio Fuel is scheduled to receive from Texas Eastern a total firm quantity of 215,400 Mcf per day. Such gas is delivered by Texas Eastern at six delivery points in western and central Ohio.

Texas Eastern states that it is informed that Ohio Fuel's customer, Dayton, desires to extend its service to New Holland, Ohio, and vicinity, which are located in the general area in which Dayton distributes gas at retail, but which do not have natural gas service.

Texas Eastern says it is informed that the service proposed by Dayton can best be rendered by Dayton receiving deliveries of natural gas from Texas Eastern's main line, since it will permit construction of the minimum amount of lateral line to New Holland and at the same time permit Dayton to provide service in the community of Waterloo enroute to New Holland.

Applicants show that they can furnish the proposed service under their existing supply contracts. Applicants' supplies are adequate for the minor service proposed, and the proposed deliveries will not adversely affect Applicants' ability to serve other customers.

Dayton will construct and operate the necessary gas supply line from Texas Eastern's pipeline and all other gas distribution facilities required to render said service.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 7, 1962, respecting the matters involved in and the issues presented by the applications. No petition to intervene or protest to the granting of the application except a petition to intervene filed by The Dayton Power and Light Company, in Docket No. CP62–3 in support of the applications and requesting that the intermediate decision procedure be waived and omitted. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) The Ohio Fuel Gas Company (Applicant) an Ohio corporation and a subsidiary of The Columbia Gas System, Inc., having its principal place of business in Columbus, Ohio, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of August 21, 1945, in Docket No. G–371 (4 FPC 1033).

(2) Texas Eastern Transmission Corporation, a Delaware corporation, having its principal place of business in Shreveport, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of October 10, 1947, in Docket No. G–880 (6 FPC 148).

(3) The proposed sale and delivery of natural gas by The Ohio Fuel Gas Company at an additional delivery point to the Dayton Power and Light Company will be made for resale in interstate commerce, subject to the jurisdiction of the Commission and such sale is subject to the requirements of Subsection (c) and (e) of Section 7 of the Natural Gas Act.

(4) The facilities proposed to be constructed and operated by Texas Eastern as hereinbefore described and as more fully described in the application herein, are to be used in the transportation and sale for resale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Texas Eastern are subject to the requirements of Subsection (c) and (e) of Section 7 of the Natural Gas Act.

(5) The construction and operation of the facilities as proposed by Texas Eastern and the sale of natural gas at an additional delivery point as proposed by Ohio Fuel are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(6) Applicants are able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(7) Public convenience and necessity require that the certificates issued hereinafter and the rights granted thereunder be conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b) and (e) of Section 157.20 of said regulations and the terms and conditions of paragraphs (c)(1), (c)(3) and (c)(4) of said section shall attach to the certificate issued to Texas Eastern Transmission Corporation.

(8) A request during the public hearing having been made by staff counsel for omission of the intermediate decision procedure, and all requirements of Section 1.30(c)(1) [18 CFR 1.30(c)(1)] of the Commission's Rules of Practice and Procedure having been satisfied, sufficient cause exists for the Commission to render its final decision in the instant proceeding.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued to The Ohio Fuel Gas Company authorizing the establishment of an additional point of delivery and sale to The Dayton Power and Light Company in Madison Township, Fayette County, Ohio, and to deliver and sell natural gas to Dayton at said additional delivery point for resale in the market area of New Holland and Waterloo, Ohio, and vicinity, as described in the application in Docket No. CP62–2, upon the terms and conditions of this order.

(B) A certificate of public convenience and necessity be and the same is hereby issued to Texas Eastern Transmission Corporation authorizing it to construct and operate the proposed facilities, as described in the application in Docket No. CP62–3, upon the terms and conditions of this order.

(C) The certificates issued by paragraphs (A) and (B) above and the rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b) and (e) of Section 157.20 of said regulations and the terms and conditions set forth in paragraphs (c)(1), (c)(3) and (c)(4) of said section shall attach to the certificate issued by paragraph (B) and to the exercise of the rights granted thereunder. In addition, Texas Eastern be and hereby is permitted to waive the provisions of Section 6.1 of the general terms and conditions of its tariff for the limited purpose of permitting Ohio Fuel to own the meter station to be built by Texas Eastern.

(D) The time within which the facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act is hereby fixed at 12 months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TAYLORSTOWN NATURAL GAS COMPANY, DOCKET NO. CP62-98

FINDINGS AND ORDER DIRECTING THE PHYSICAL CONNECTION OF FACILITIES AND SALE OF NATURAL GAS

(Issued March 19, 1962)

On October 16, 1961, as supplemented on January 2, 1962, Taylorstown Natural Gas Company (Applicant) filed in Docket No. CP62-98 an application pursuant to Section 7(a) of the Natural Gas Act for an order of the Commission directing The Manufacturers Light and Heat Company (Manufacturers) to establish physical connection of its facilities with those which Applicant operates, and to sell and deliver to Applicant natural gas for resale and distribution in Blaine, Buffalo, Donegal, and East Finley Townships and Claysville Borough, all in Washington County, Pennsylvania, all as more fully set forth in the application, as supplemented.

Applicant, which is regulated by the Pennsylvania Public Utility Commission, states that it serves about 1,000 customers at retail in the above-named communities. For more than 60 years Applicant's source of natural gas supply has been from local wells in the Taylorstown Field. Applicant both produces and purchases gas in this area. This field is now approaching depletion, and since no further development is anticipated, Applicant finds it necessary to augment its gas supply by purchase of gas from Manufacturers, an interstate pipeline whose facilities are located in this area.

To serve Applicant as requested Manufacturers will have to build two separate connections with Applicant's system and install meters in the vicinity of Taylorstown, Pennsylvania. Applicant proposes to construct the necessary pipeline between the taps on Manufacturers' system and its own system at a cost of about $200.

Applicant considers the 1960 requirements of 190,186 Mcf of gas at 14.73 psia and the peak and average days, respectively, of 2,184 and 522 Mcf of gas to be typical of the area's future requirements. Applicant estimates the remaining

reserve in the Taylorstown field to be 1,000,000 Mcf of gas and the decline in production to be about 10 percent annually. To meet this decline in production Applicant will require from Manufacturers annual volumes of about 40,000 Mcf of gas and up to 1,000 Mcf of gas per day on peak days. Applicant will purchase gas under Manufacturers' CDS–1 Rate Schedule.

Manufacturers filed its answer to the subject application on November 17, 1961, as supplemented on December 18, 1961, stating that it is able and willing to render the proposed service.

Notice of the application was published in the Federal Register on February 16, 1962 (27 FR 1469). No petition to intervene or protest to the granting of the application has been received.

The Commission finds:

(1) Applicant, Taylorstown Natural Gas Company, a Pennsylvania corporation having its principal place of business in Taylorstown, Pennsylvania, is a public utility subject to the jurisdiction of the Pennsylvania Public Utility Commission and is duly authorized to engage in the business of distributing and selling natural gas in Pennsylvania.

(2) The Manufacturers Light and Heat Company, a Pennsylvania corporation having its principal place of business in Pittsburgh, Pennsylvania, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of December 29, 1944, in Docket No. G–593, *et al.* (4 FPC 821)

(3) It is necessary and desirable in the public interest to direct The Manufacturers Light and Heat Company to establish physical connection of its transmission facilities with those of the Taylorstown Natural Gas Company in Blaine, Buffalo, Donegal, and East Finley Townships and Claysville Borough, Washington County, Pennsylvania, and to sell and deliver natural gas to Taylorstown Natural Gas Company under Manufacturers' appropriate rate schedule on file with the Commission, for resale and distribution in the aforesaid communities.

(4) Manufacturers should not be required to furnish gas in excess of 1,000 Mcf per day for the service herein directed.

(5) Applicant should commence taking gas from Manufacturers as directed hereinafter within one year from the date on which this order issues.

The Commission orders:

(A) The Manufacturers Light and Heat Company be and it is hereby directed to establish physical connection of its transmission facilities with those of the Taylorstown Natural Gas Company in Washington County, Pennsylvania, and to sell and deliver natural gas to Applicant under Manufacturers' appropriate rate schedule on file with the Commission, for distribution and resale in the communities of Blaine, Buffalo, Donegal and East Finley Townships and Claysville Borough, as hereinbefore described and as more fully described in the application and supplement in this proceeding.

(B) Manufacturers shall not be required to furnish gas in excess of 1000 Mcf per day for the service herein directed.

(C) Applicant shall commence taking gas from Manufacturers as hereinbefore directed within one year from the date on which this order issues.

(D) Manufacturers shall report to the Commission in writing and under oath the date of commencement of service to Applicant within 10 days after such service has begun.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

UNITED GAS PIPE LINE COMPANY, DOCKET NO. G–12569

FINDINGS AND ORDER FURTHER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 19, 1962)

On November 8, 1961, United Gas Pipe Line Company (Movant) filed in Docket No. G–12569 a motion to further amend the order in said docket issued on August 23, 1957, all as more fully set forth in the motion.

Movant seeks authorization to increase deliveries of natural gas to Coastal Chemical Corporation, Pascagoula, Mississippi, from 8,500 Mcf per day to 20,000 Mcf per day on an interruptible basis. There is sufficient capacity in the existing authorized facilities to render the increased service which is required due to an expansion of the Coastal Chemical Corporation plant.

Notice of the motion was published in the Federal Register on February 20, 1962 (27 FR 1584). No protest to the granting of the motion or petition to intervene has been received.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act, and the public convenience and necessity require that the certificate heretofore issued in Docket No. G–12569, issued August 23, 1957, as amended, be further amended as hereinafter ordered.

The Commission orders:

(A) The certificate of public convenience and necessity heretofore issued in Docket No. G–12569 on August 23, 1957, as amended, be and the same is hereby further amended to authorize United Gas Pipe Line Company to deliver up to 20,000 Mcf of gas on an interruptible basis to the Coastal Chemical Corporation plant at Pascagoula, Mississippi.

(B) In all other respects said certificate shall remain unchanged and in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

UNITED GAS PIPE LINE COMPANY, DOCKET NO. CP62–150

FINDINGS AND ORDER PERMITTING AND APPROVING ABANDONMENT OF FACILITIES

(Issued March 19, 1962)

On December 26, 1961, United Gas Pipe Line Company (Applicant) filed in Docket No. CP62–150 an application pursuant to Section 7(b) of the Natural Gas Act for permission and approval to abandon natural gas facilities as hereinafter described and as more fully described in the application.

Applicant seeks authorization to abandon and remove 0.004 mile of 8⅝" O.D. pipeline and a dual 6" orifice meter station and appurtenant facilities in Jefferson County, Texas. The facilities proposed for abandonment were installed in 1952 for the purpose of delivering gas to Magnolia Petroleum Company [1] for use in its operation of an oil refinery located at Beaumont, Texas. Socony has

[1] Predecessor in interest to Socony Mobil Oil Company (Socony).

advised Applicant that it sees no immediate use for the facilities and has requested cancellation of the gas sales contract to which Applicant has agreed.

The subject facilities have been utilized directly in connection with service to Socony and are not required following the termination of the gas sales contract with Socony. The original cost of the subject facilities was $3,826.43.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 13, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, United Gas Pipe Line Company, a Delaware corporation having its principal place of business in Shreveport, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of January 20, 1942, in Docket No. G-216 (3 FPC 3).

(2) The facilities to be abandoned, as hereinbefore described and as more fully described in the application in this proceeding, are subject to the jurisdiction of the Commission, and abandonment of such facilities is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(3) Such abandonment by Applicant is permitted by the public convenience and necessity, and an order permitting and approving same should be issued as hereinafter ordered.

(4) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Permission for an approval of the abandonment by the United Gas Pipe Line Company of the facilities hereinbefore described, and as more fully described in the application in this proceeding, be and the same is hereby granted.

(B) Applicant shall advise the Commission of the date of the removal of the equipment within ten days after the completion thereof.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

UNITED FUEL GAS COMPANY, DOCKET NO. G-20270

ORDER CONDITIONALLY APPROVING RATE SETTLEMENT AND PROVIDING FOR LIMITED HEARING

(Issued March 20, 1962)

On November 17, 1961, United Fuel Gas Company (United Fuel), an affiliate in the Columbia Gas System, Inc., filed a motion requesting that the Commission issue an order approving a proposed rate settlement based upon a Stipulation and Agreement and a Supplement thereto submitted with such

motion. The Stipulation and Agreement dated June 1, 1961 (attached hereto as Exhibit I*) was executed by United Fuel, all of its customers, and certain non-customer intervenors following a field investigation by the Commission staff of United Fuel's books, records, and operations and following conferences (concluded May 11, 1961) between United Fuel, its customers, non-customer intervenors, and members of the Commission staff. Simultaneously, United Fuel also filed a supplemental agreement dated October 16, 1961 (attached hereto as Exhibit II*) executed by the signatories to the settlement agreement other than City of Pittsburgh, Pennsylvania.

The Stipulation and Agreement provides for two costs of service[1] which are to be used as bases for determination of rate design after hearing. The first cost of service is for the test year ended March 31, 1960, and will be used as the basis for determining rates from April 5, 1960, the date increased rates originally proposed herein became effective subject to refund, until May 1, 1961; it reflects a reduction in jurisdictional revenues of about $8,949,300 on an annual basis. The second cost of service is based on the same test year but with adjustments to reflect increased purchased gas costs[2]; it will be used as the basis for determining rates from and after May 1, 1961, and reflects a reduction in jurisdictional revenues of about $8,325,000 on an annual basis.

Under that Stipulation and Agreement, two issues are reserved for hearing and determination by the Commission in this proceeding: (1) the level of the demand and commodity components of the rate in United Fuel's contract demand service rate schedule and the rate levels in its other rate schedules; and (2) the depreciation rates of United Fuel to be applied to its underground storage and transmission properties and to its Kenova Extraction Plant. After hearing and determination of the above issues, United Fuel will appropriately revise its present rates, effective subject to refund in this proceeding, and will make refunds, plus interest, reflecting the revisions in rates.

The Stipulation and Agreement also provides that United Fuel will not file increased rates and charges with the Commission prior to April 1, 1962, except in the event and to the extent that Tennessee Gas Transmission Company (Tennessee Gas) files for increased rates and charges to United Fuel. In addition, United Fuel shall further reduce its rates and make appropriate refunds if (1) Boldman Compressor Station, reflected in the costs of service (see Exhibit I, Appendix C), is not transferred to United Fuel by Atlantic Seaboard Corporation[3]; and (2) if the State of Texas refunds to United Fuel severance beneficiary taxes reflected in the costs of service. Finally, United Fuel will further reduce its rates to the extent suppliers reduce rates to United Fuel which are reflected in the settlement costs of service; and United Fuel will make refunds to the extent and in the manner that suppliers make refunds to United of charges reflected in the costs of service.

The Supplement to the Agreement purports to revise a provision in the Agreement concerning the treatment of Tennessee Gas' present rates and charges to United Fuel. Prior to settlement negotiations, Tennessee Gas had filed increased

* Omitted in printing.

[1] See Exhibit I, Appendix A. The total costs there stated should be reduced by the elimination of adjustment (5), as provided in the settlement agreement, in accord with the recently final decision in *City of Lexington, et al.* v. *FPC*, 295 F. 2d 109 (CA4, 1961). This reduction renders moot certain objections filed by City of Pittsburgh, the Pennsylvania Public Utility Commission, and the Kentucky Cities group.

[2] These adjustments reflect increases by Columbian Fuel Corporation and increases which are effective subject to refund in certain Louisiana independent producer proceedings and in *United Carbon Company*, Docket No. RI61-269.

[3] Approval for the transfer of this and other facilities is being sought in the proceeding in Docket No. CP61-107.

rates and charges which become effective subject to refund on April 5, 1960, in the proceeding in Docket No. G–19983. The Commission determined that the rate of return reflected in Tennessee Gas' increased rates was excessive and by order of August 9, 1960, accordingly required Tennessee Gas to make refunds and to file interim revised rates subject to further determinations in Docket G–19983. It was provided in the United Fuel settlement Agreement, among other things, that Tennessee Gas' interim rates are to be reflected in the settlement costs of service. Subsequent to the execution of the settlement Stipulation and Agreement, the United States Court of Appeals for the Fifth Circuit affirmed on appeal the Commission's determination of Tennessee Gas' rate of return but disapproved the requirement that Tennessee Gas file interim rates.[4] Thereafter the signatories to the Stipulation and Agreement, other than City of Pittsburgh, executed a supplementary agreement providing in effect that the settlement costs of service be increased to reflect rates and charges to United Fuel at levels originally filed by Tennessee Gas in Docket No. G–19983. The Kentucky Cities and Pennsylvania Public Utility Commission, non-signatories to the Stipulation and Agreement, and City of Pittsburgh have filed objections to the Supplement.

Upon review of the Stipulation and Agreement (Exhibit I), the studies in support thereof, and the Supplement thereto, we deem the proposed rate settlement as based on said Stipulation and Agreement and the studies in support thereof to be in the public interest, if modified as hereinafter indicated. However as to the Supplement, there appears to be no imminent prospect that the rates originally filed by Tennessee in Docket No. G–19983 will be reinstituted. The Supplement therefore appears unwarranted and should be disapproved. If changed conditions after hearing on the reserved issues warrant our reconsidering the proposal in the Supplement, United may then seek such relief as it deems necessary.

On our own motion, we deem it appropriate to add two conditions to our approval of the proposed rate settlement. The Agreement provides for flow-through by United Fuel of refunds from suppliers to the extent and in the same manner that the suppliers make refunds of charges reflected in the settlement costs of service. Since there will be a hearing on rate design it appears more appropriate to leave for determination in such hearing the manner in which refunds and rate reductions shall be made by United Fuel. We shall, therefore, condition our approval of the settlement agreement by providing for hearing on the manner of reducing rates and making refunds.

Another condition is appropriate with regard to the proceeding in Docket No. CP61–107. United Fuel and certain affiliates are seeking approval in that proceeding for the transfer of certain facilities to United Fuel. The settlement costs of service now reflect the costs of one of those facilities, Boldman Compressor Station[5], but not other facilities which may be transferred to United Fuel. We believe that United Fuel should be permitted to file revised costs of service and associated revised rates, subject to our approval, which it may deem necessary and appropriate to transfer of facilities approved in the proceeding in Docket N o. CP61–107.[6]

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[4] *Tennessee Gas Transmission Company* v. *F.P.C.*, 293 F. 2d 761 (CA5, 1961), cert. granted, sub. nom. *F.P.C.* v. *Tennessee Gas Transmission Company*. Fifth Circuit reversed insofar as it set aside interim order, 371 U.S. 145 (1962).

[5] These costs will be refunded if the station is not transferred to United Fuel.

[6] Similarly, in *Atlantic Seaboard Corporation*, Docket No. G–20272 (orders issued December 29, 1961, and February 19, 1962, 26 FPC 945 and 27 FPC 369, respectively) we required Atlantic Seaboard to reduce its rates if it transferred subject facilities to United Fuel.

The Commission finds:

(1) The settlement of the proceeding in Docket No. G–20270 on the basis of the Stipulation and Agreement (Exhibit I), as hereinafter modified, is reasonable, proper, and in the public interest in carrying out the provisions of the Natural Gas Act and the proposed rate settlement based thereon should be approved and made effective subject to the terms and conditions hereinafter ordered, but the Supplement (Exhibit II) should be disapproved and rejected.

(2) The rates and charges in United Fuel's revised tariff sheets comprising Rate Schedules CDS–1, AOS–1, SGS–1, and ES–1, tendered for filing in this proceeding, have not been shown to be just, reasonable, or otherwise lawful under the terms and provisions of the Natural Gas Act, and should be disallowed and denied as hereinafter ordered.

(3) A hearing should be held in this proceeding as hereinafter provided.

The Commission orders:

(A) The increased rates and charges tendered for filing in this proceeding hereby are disallowed and denied.

(B) The settlement of this proceeding as proposed in the Stipulation and Agreement discussed above (Exhibit I hereto), is approved and made effective.

(C) The Supplement to the Stipulation and Agreement filed by United Fuel in this proceeding is disapproved and rejected.

(D) Notwithstanding the provision in the Agreement for a moratorium on increased rate filings by United Fuel, in the event and to the extent that transfers of facilities to United Fuel are approved in the proceeding in Docket No. CP61–107, United Fuel may tender for filing, subject to approval by the Commission, revisions to the settlement costs of service for the period from and after the date of transfer as may be permitted by, or otherwise appropriate to the transfer of facilities in the proceeding in Docket No. CP61–107; if all the issues to be heard in the proceeding in Docket No. G–20270 have been determined prior to said approval of the transfer of facilities, United Fuel may also tender for filing, subject to approval of the Commission, revisions in rates appropriate to the revised costs of service tendered for filing as hereby permitted.

(E) A hearing shall be held in this proceeding to commence on a date to be fixed by notice of the Secretary or order of the Commission, concerning the following issues:

1. The level of the demand and commodity components of the rate in Rate Schedule CDS–1 and the rate levels in Rate Schedules AOS–1, SGS–1, and ES–1, included in United Fuel's FPC Gas Tariff, Fifth Revised Volume No. 1 applicable (i) to the period April 5, 1960, through April 30, 1961, and (ii) to be effective on and after May 1, 1961, until superseded.

2. The manner in which United Fuel shall make refunds or further revise its rates pursuant to the settlement agreement or the provisions of Paragraph D above.

3. The depreciation rates of United Fuel to be applied to its underground storage and transmission properties and to its Kenova Extraction Plant.

(F) United Fuel shall, over the signature of a responsible officer, file with the Commission, within 30 days from the date of issuance of this order, in writing and under oath, an original and one copy of its acceptance or rejection of the terms and conditions of this order.

(G) This order is without prejudice to any findings or orders which have been or may be made hereafter by the Commission, and is without prejudice to claims or contentions which may be made by the Commission, United Fuel, the Commission staff, or any affected party herein, in any proceeding now pending or hereafter instituted by or against United Fuel or any other companies, persons, or parties affected by this order.

APPENDIX A

Development of stipulated cost of service for 12 months ended March 31, 1960 (based on staff study II and adjustments agreed to at settlement conferences) and comparison of such cost of service with revenue at filed rates effective April 5, 1960

Line number	Adjustment number		Applicable to production and transmission operations			Applicable to jurisdictional wholesale sales		
			Total	Demand	Commodity	Total	Demand	Commodity
1, 2		Total allocated cost of service to jurisdictional wholesale sales per staff study II, Table I (see Sheet 2 herein)				$170,104,759	$42,797,606	$127,307,153
3, 4		Agreed-to adjustments to staff cost of service to determine basis for rates effective April 5, 1960, to May 1, 1961						
5		Restore booked depreciation rates						
6	1	Kenova extraction plant:						
7		Depreciation expense	$237,012		$237,012	214,316		214,316
8		Return at 6.44%	(10,985)		(10,985)	(9,933)		(9,933)
9		Federal income tax	(10,180)		(10,180)	(9,205)		(9,205)
10		Total Kenova extraction plant	215,847		215,847	195,178		195,178
11	2	Underground storage:						
12		Depreciation expense	33,169	$16,584	16,585	29,636	14,639	14,997
13		Return at 6.44%	(4,869)	(2,435)	(2,434)	(4,351)	(2,150)	(2,201)
14		Federal income tax	(4,513)	(2,256)	(2,257)	(4,032)	(1,991)	(2,041)
15		Total underground storage	23,787	11,893	11,894	21,253	10,498	10,755
16	3	Transmission:						
17		Depreciation expense	325,893	162,947	162,946	291,182	143,840	147,342
18		Return at 6.44%	(44,139)	(22,069)	(22,070)	(39,438)	(19,481)	(19,957)
19		Federal income tax	(40,907)	(20,454)	(20,453)	(36,550)	(18,056)	(18,491)
20		Total transmission	240,847	120,424	120,423	215,194	106,303	108,891
21		Net adjustment to reflect booked depreciation rates	480,481	132,317	348,164	431,625	116,801	314,824
22	4	Reflect approved book method of pricing gas into storage	16,181	15,424	757	14,300	13,615	685
23, 24	5	Adjust Federal and State income taxes to reflect claims regarding production tax benefits (Article V of stipulation):						
25		Intangible productive well drilling	3,266,672		3,266,672	2,953,855		2,953,855
26		Statutory depletion	1,160,285		1,160,285	1,049,176		1,049,176
27		Total	4,426,957		4,426,957	4,003,031		4,003,031
28	6	Reduce rate of return from 6.5% to 6.44%	(199,448)	(61,673)	(138,775)	(179,044)	(53,558)	(125,486)
29	7	Reduction in cost of transportation by Columbia Gulf	(602,850)	(301,129)	(301,721)	(538,646)	(265,818)	(272,828)
30	8	Reduce consolidated tax savings from 8.35% to 7.5%	215,439	104,936	110,503	192,552	92,631	99,921

31	9	Increased purchased gas costs from Louisiana producers effective in August and September 1960	189,731		189,731	171,562		171,562
32	10	Increased exploration and development costs	667,173		667,173	603,285		603,285
33		Net adjustment	5,193,664	(109,125)	5,302,789	4,698,665	(96,329)	4,794,994
34, 35		Adjusted allocated cost of service to jurisdictional wholesale sales to be used as basis for rates effective April 5, 1960, to May 1, 1961				174,803,424	42,701,277	132,102,147
36		Revenues at filed rates effective April 5, 1960				179,749,737		
37		Annual excess revenues under filed rates				4,946,313		
38, 39		Agreed—to additional adjustments to cost of service to determine basis for rates effective May 1, 1961						
40	11	Increased purchased gas costs from:						
41		(a) Louisiana Producers effective in April and May 1961	541,589		541,589	489,726		489,726
42		(b) United Carbon Company effective in May 1961	92,328		92,328	83,487		83,487
43		(c) Columbian Fuel Corporation effective in May 1961	56,510		56,510	51,099		51,099
44		Total additional adjustment	690,427		690,427	624,312		624,312
45, 46		Adjusted allocated cost of service to jurisdictional wholesale sales to be used as basis for rates effective May 1, 1961				175,427,736	42,701,277	132,726,459
47		Revenues at filed rates effective April 5, 1960				179,749,737		
48		Annual excess revenues under filed rates				4,322,001		

APPENDIX A

Cost of Service—12 Months Ended March 31, 1960, Including Boldman Compressor Station

Line number	Particulars	As adjusted		
	(1)	Total (2)	Demand (3)	Commodity (4)
1	Cost of Service:			
2	Cost of produced and purchased gas	$128,620,997	$20,413,546	$108,207,451
3	Cost of L.P. gas-air	285,621	285,621	
4	Cost of products extraction	(1,891,291)		(1,891,291)
5	Cost of underground storage	9,308,665	4,387,260	4,921,405
6	Cost of transmission	52,922,137	23,383,266	29,538,871
7	Total production and transmission cost of service	189,246,129	48,469,693	140,776,436
9	Applicable to jurisdictional wholesale sales per-			
10	percent (demand—average of 3-day peak period)		88.274	90.424
11				
12	Amount	$170,081,821	$42,786,137	$127,295,684
13	Regulatory commission expenses	22,938	11,469	11,469
14	Total allocated cost of service to jurisdictional			
15	wholesale sales	170,104,759	42,797,606	127,307,153

Note. The above is a copy of Staff Cost of Service included in data which was distributed by the Staff on April 10, 1961, titled "Study II, Table I, Sheet 1".

Rate base for 12 months ended March 31, 1960, computed from staff studies with adjustments to reflect settlement agreement

Line Number	Description	Total Company	Applicable to Production and Transmission Operations						Distribution and Other	F.P.C. Rate Case
			Total	Liquified Petroleum	Other Prod., Gath. & Gas Sup.	Products Extraction	Underground Storage	Transmission		
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1, 2	Total rate base computed from staff studies distributed April 10, 1961	$182, 735, 645	$166, 041, 796	$1, 320, 076	$59, 758, 123	$7, 806, 534	$53, 753, 680	$43, 403, 383	$16, 691, 106	$2, 743
3, 4	Adjustments to staff rate base to reflect settlement agreement:									
5	Reflecting effect of booked depreciation accrual rates:									
6										
7	Products Extraction Plant	(170, 585)	(170, 585)			(170, 585)				
8	Underground Storage Plant	(75, 603)	(75, 603)				(75, 603)			
9	Transmission Plant	(685, 385)	(685, 385)					(685, 385)		
10	Total	(931, 573)	(931, 573)			(170, 585)	(75, 603)	(685, 385)		
11	Adjustments to working capital due to:									
12, 13	Book method of pricing gas into storage	(176, 911)	(176, 913)		5, 495		(182, 408)			(1)
14, 15, 16	Reduction in cost of transportation by Columbia Gulf Transmission Co	(3, 900)	(3, 901)		121		(4, 022)		3	1
17, 18	Use of 6.44% return vs. 6.5% used by staff	50, 182	45, 528		45, 528				4, 653	1
19	Consolidated tax savings from 8.35% to 7.50%	(45, 337)	(39, 032)	(435)		(3, 314)	(21, 252)	(14, 031)	(6, 304)	(1)
20	Total adjustments	(1, 107, 539)	(1, 105, 891)	(435)	51, 144	(173, 899)	(283, 285)	(699, 416)	(1, 648)	
21	Revised total rate base	181, 628, 106	164, 935, 905	1, 319, 641	59, 809, 267	7, 632, 635	53, 470, 395	42, 703, 967	16, 689, 458	2, 743

APPENDIX A TO SUPPLEMENTAL AGREEMENT

Cost of service for 12 months ended March 31, 1960 (based on staff study II as adjusted to reflect agreement reached at settlement conferences and further adjusted to include purchased gas costs at Tennessee Gas Transmission Company's original rates effective April 5, 1960, in Docket No. G–19983) and comparison of such cost of service with revenue at filed rates effective April 5, 1960

Line No.		Applicable to production and transmission operations			Applicable to jurisdictional wholesale sales		
		Total (1)	Demand (2)	Commodity (3)	Total (4)	Demand (5)	Commodity (6)
1, 2, 3	Total allocated cost of service to jurisdictional wholesale sales per staff study II, Table I (see Appendix A, sheet 2 of 3 of proposed settlement agreement previously distributed)				$170, 104, 759	$42, 797, 606	$127, 307, 153
4, 5, 6	Agreed-to adjustments to staff cost of service to determine basis for rates effective April 5, 1960, to May 1, 1961 (see appendix A, sheet 1 of 3, line 33 of proposed settlement agreement previously distributed)	$5, 193, 664	($109, 125)	$5, 302, 789	4, 698, 665	(96, 329)	4, 794, 994
7, 8, 9	Adjusted allocated cost of service to jurisdictional wholesale sales (per Appendix A, sheet 1 of 3, line 35 of proposed settlement agreement previously distributed)				174, 803, 424	42, 701, 277	132, 102, 147
10, 11, 12, 13	Adjustments to staff cost of service for increased purchased gas costs from Tennessee Gas Transmission Co. to reflect Tennessee's original rates in Docket No. G–19983 effective April 5, 1960 (subject to refund) over Tennessee's revised rates per FPC order issued August 9, 1960:						
14	Purchased gas	2, 494, 025	2, 468, 777	25, 248	2, 202, 118	2, 179, 288	22, 830
15	Net gas delivered and withdrawn from storage	(35, 637)	(35, 637)		(31, 458)	(31, 458)	
16	Return at 6.44%	8, 821	4, 410	4, 411	7, 882	3, 893	3, 989
17	Federal income taxes	8, 175	4, 088	4, 087	7, 305	3, 609	3, 696
18	State income taxes	82	41	41	73	36	37
19	Total	2, 475, 466	2, 441, 679	33, 787	2, 185, 920	2, 155, 368	30, 552
20, 21	Adjusted allocated cost of service to jurisdictional wholesale sales to be used as basis for rates effective April 5, 1960, to May 1, 1961				176, 989, 344	44, 856, 645	132, 132, 699
22	Revenue at filed rates effective April 5, 1960				179, 749, 737		
23	Annual excess revenue under filed rates				2, 760, 393		
24, 25, 26	Agreed-to additional adjustments to cost of service to determine basis for rates effective May 1, 1961 (see Appendix A, sheet 1 of 3, line 44 of proposed settlement agreement previously distributed)	690, 427		690, 427	624, 312		624, 312
27, 28	Adjusted allocated cost of service to jurisdictional wholesale sales to be used as basis for rates effective May 1, 1961 (line 21 + line 26)				177, 613, 656	44, 856, 645	132, 757, 011
29	Revenue at filed rates effective April 5, 1960				179, 749, 737		
30	Annual excess revenue under filed rates				2, 136, 081		

APPENDIX B

Computation of adjustment number (5) to cost of service (Appendix A) to reflect the company's position regarding the reserved production tax issues (Article V of stipulation)

Line No.		Total amount	Applicable to jurisdictional wholesale sales
1	Intangible productive well drilling costs:		
2	Applicable to production and transmission operations:		
3, 4, 5	Addition to taxable income—reversal of "deductions made on paid method" intangible productive well drilling costs	$3, 543, 785	
6, 7	Deduction from taxable income—gas well construction depreciation expense	53, 889	
8	Net deduction eliminated in computing taxes	3, 489, 896	
9	Resulting increase in:		
10, 11	Federal income tax (line 8 times effective tax ratio of 92.678227%)*	3, 234, 374	
12, 13	Kentucky State income tax (line 8 × 0.917% + 99.083%)	32, 298	
14	Total income taxes (lines 10 through 13)	3, 266, 672	
15, 16	Portion applicable to jurisdictional wholesale sales (line 14 × 90.424%)		$2, 953, 855
17	Depletion:		
18	Applicable to production and transmission operations:		
19, 20, 21	Addition to taxable income—reversal of "deduction made on paid method" statutory depletion	1, 319, 039	
22, 23	Deduction from taxable income—depletion expense included in cost of service	79, 467	
24	Net deduction eliminated in computing taxes	1, 239, 572	
25	Resulting increase in:		
26, 27	Federal income tax (line 24 times effective tax ratio of 92.678227%)*	1, 148, 813	
28, 29	Kentucky State income tax (line 24 × 0.917% + 99.083%)	11, 472	
30	Total income taxes (lines 25 through 29)	1, 160, 285	
31	Portion applicable to jurisdictional wholesale sales (line 30 × 90.424%)		1, 049, 176
32	Total effect of above two items on jurisdictional wholesale sales		4, 003, 031

*Tax ratio based on 7.50% consolidated tax savings.

Staff cost of service for 12 months ended March 31, 1960, adjusted, to be used as basis for rates effective April 5, 1960, to May 1, 1961, showing the effect of including and also excluding Boldman Compressor Station (includes rate of return at 6.44% and consolidated tax savings of 7.5%)

Line No.		Total (1)	Demand (2)	Commodity (3)
1	Including boldman compressor station:			
2, 3	Total company production and transmission cost of service	$194,439,793	$48,360,568	$146,079,225
4	Applicable to jurisdictional wholesale sales:			
5	Percent		88.274	90.424
6	Amount	$174,780,486	$42,689,808	$132,090,678
7	Regulatory commission expenses	22,938	11,469	11,469
8, 9	Total allocated cost of service to jurisdictional wholesale sales [a]	$174,803,424	$42,701,277	$132,102,147
10	Excluding boldman compressor station:			
11, 12	Total company production and transmission cost of service	$193,861,815	$48,117,497	$145,744,318
13	Applicable to jurisdictional wholesale sales:			
14	Percent		88.255	90.398
15	Amount	$174,216,028	$42,466,097	$131,749,931
16	Regulatory commission expenses	22,938	11,469	11,469
17, 18	Total allocated cost of service to jurisdictional wholesale sales	$174,238,966	$42,477,566	$131,761,400
19	Effect of boldman compressor station:			
20, 21, 22	Effect on allocated cost of service to jurisdictional wholesale sales (line 9–line 18)	$564,458		
23, 24, 25, 26, 27	Additional revenue to be derived by United Fuel Gas Co. from Atlantic Seaboard Corp., due to proposed transfer of boldman compressor station	[b] 470,689		
28	Net effect	$93,769		

[a] Per Appendix A, sheet 1 of 3, line 35 to settlement agreement.
[b] At filed rates effective April 5, 1960, and is subject to adjustment upon final rate determination.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

UNITED STATES DEPARTMENT OF THE INTERIOR, BONNEVILLE POWER ADMINISTRATION, DOCKET NO. E–6905

ORDER CONFIRMING AND APPROVING RATES AND CHARGES

(Issued March 20, 1962)

The Secretary of the Interior, on behalf of the Bonneville Power Administration (Bonneville), on January 24, 1962, filed with the Federal Power Commission for confirmation and approval, pursuant to the Bonneville Act (50 Stat. 731), as amended, proposed wholesale rates and charges for electric energy supplied under Bonneville's approved Wholesale Power Rate Schedule E–4 and General Rate Schedule Provisions, subject to modifications, in accordance with a power sales contract executed November 15, 1961, by Bonneville and the City of Grand Coulee, Washington.

The Coulee Dam Community Act of 1957, approved August 30, 1957 (71 Stat. 524), recites that its purpose, in connection with the Columbia Basin project is, in part, to authorize the disposal of certain Federal property in the immediate vicinity of the City of Grand Coulee to reduce restrictions on the growth thereof.

In furtherance of its purpose, the Act authorizes, among other things, the sale of lands and improvements in the Grand Coulee area acquired or built by the United States for the construction and operation of Grand Coulee Dam and not needed for Federal purposes, except that ownership of any Federally owned municipal-type property, including street-lighting, electric feeder lines, and power distribution systems situated in and serving the town of Coulee Dam, Washington, and Grand Coulee areas is to be transferred without cost to the municipal corporation embracing such area or Grand Coulee. Furthermore, under Section 7(c) of the Act, the Secretary of the Interior is authorized to make available, as power and energy reserved for the operation and maintenance of the Columbia Basin project, for users in communities within three and one-half miles of Grand Coulee Dam served by municipally-owned distribution systems, such amount of power and energy as, in his judgment, is needed to meet load requirements for space-heating purposes existing at the time of incorporation of the municipality. It is also provided in Section 7(c) that such power and energy may be made available directly to the users or indirectly through distributing agencies for a period of 10 years from the date of the Act and may be at such special rates as the Secretary of the Interior finds to be proper but at not less than cost. The Secretary states that the City of Grand Coulee's municipal electric system, which was founded in 1940, is located within three and one-half miles of the Grand Coulee Dam and may purchase its electric space-heating requirements at the special rates provided by the Act. The Act makes no provision for confirmation and approval by the Commission of the special rates for electric space-heating, which is supplied from power and energy reserved for the operation and maintenance of the Columbia Basin project.

Subsequent to the enactment of, and as contemplated by, the Coulee Dam Community Act, the Secretary of the Interior estimated the monthly amounts of power and energy needed by the City for space-heating purposes, established one mill per kilowatt-hour as the rate therefor, and agreed with the City to furnish its space-heating requirements at the rate of one mill per kilowatt-hour, all as more fully appears in the above-mentioned power sales contract (contract).

In addition to providing for the supplying of the City's electric space-heating requirements, the contract also provides that the City's remaining electric requirements for resale and municipal purposes not provided for under the Coulee Dam Community Act will be supplied by Bonneville under its aforementioned Rate Schedule E–4 and rate schedule provisions, subject to modifications set forth in the contract. The modifications propose that Section 4 of Rate Schedule E–4, wherein it is provided that a customer receiving electric energy under such schedule must take or pay thereunder for not less than 90% of his total electric requirements, shall not be applicable to the contract, and that the definition of measured demand in section 2.2 of the rate schedule provisions shall be amended so that measured demand shall be the remainder obtained by subcontracting from the largest of the thirty-minute integrated demands for each billing month at which electric energy is delivered under the contract the number of kilowatts estimated for such month to meet space-heating requirements, provided, however, that such remainder shall not be greater than the number of kilowatts resulting from a 50% load factor usage, nor less than the number of kilowatts resulting from a 70% load factor usage, based on the remaining energy obtained by subtracting from the total number of kilowatt-hours delivered during each billing month the number of kilowatt-hours estimated for such month to meet space-heating requirements.

It is also specified in the contract that the electric energy to be used for billing purposes during any month under Rate Schedule E–4 shall be the remainder obtained by subtracting from the total number of kilowatt-hours delivered during each billing month the number of kilowatt-hours estimated for such month to meet space-heating requirements. The contract is effective for the period commencing October 20, 1961, and ending August 30, 1967.

In support of the proposed modifications of Rate Schedule E–4 and the rate schedule provisions, the Secretary of the Interior represents that studies made by Bonneville indicate that this rate schedule, assuming the modifications be come effective, will result in a lower cost of power than under any other available alternate firm power rate schedule of Bonneville and for this reason the City has elected to purchase power under Rate Schedule E–4 as modified by the contract of November 15, 1961. He also states that these modifications are necessary to carry out the advantages intended under the Coulee Dam Community Act.

By order issued December 16, 1959, Docket No. E–6887, the Commission approved Bonneville's Wholesale Power Rate Schedule E–4, among others, and General Rate Schedule Provisions applicable thereto, for a period beginning December 20, 1959, and terminating December 19, 1964.

The Commission finds:

It is appropriate for the purposes of the Bonneville Act that the proposed rates and charges for electric power, in addition to space-heating requirements, supplied in accordance with the contract between Bonneville and the City of Grand Coulee, Washington, referred to above, be confirmed and approved for a period beginning with the date of issuance of this order and ending December 19, 1964, as hereinafter provided.

The Commission orders:

The rates and charges for electric power, in addition to space-heating requirements, supplied in accordance with the contract between Bonneville and the City of Grand Coulee, Washington, referred to above, are hereby confirmed and approved for a period beginning with the date of issuance of this order and ending December 19, 1964.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CHRISTIE, MITCHELL AND MITCHELL COMPANY, ET AL., DOCKET NO. G–15033

ORDER DENYING MOTION TO TERMINATE PROCEEDING

(Issued March 21, 1962)

Christie, Mitchell and Mitchell Company, *et al.* (Respondent), has heretofore tendered for filing a proposed increased rate which was suspended and subsequently placed in effect subject to refund. The proposed increased rate is designated Supplement No. 10 to Respondent's FPC Gas Rate Schedule No. 11.

On February 5, 1962, Respondent filed a motion to terminate this proceeding.[1] In support of its motion, Respondent recites that the increased rate does not

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[1] The document was styled "Motion to Delete Refund Provision." Inasmuch as the effect of such action would be to terminate the proceeding, the document is herein considered as a motion to terminate.

exceed the applicable area price level established by the Commission's Statement of General Policy No. 61–1, as amended.

In its Statement of General Policy No. 61–1, 24 FPC 818, the Commission said that the price standards thereby established apply to pipeline quality gas as that term is generally understood in each area. The gas sold under Respondent's rate schedule involved herein is not of pipeline quality. When an adjustment is made for the processing charge to bring the gas up to pipeline quality, the rate exceeds the applicable area price level. Accordingly, Respondent's motion should be denied.

The Commission finds:

For the reasons hereinabove stated, Respondent's motion to terminate the proceeding in Docket No. G–15033 should be denied.

The Commission orders:

Respondent's motion to terminate the proceeding in Docket No. G–15033 is hereby denied.

THE OHIO OIL COMPANY, OPERATOR, ET AL., DOCKET NO. G–15385; SOUTHWEST NATURAL PRODUCTION COMPANY, G–15460, G–19112; JAMES R. NOWERY AND B. M. NOWERY, JR., G–16190; NORMAN V. KINSEY, JR., ET AL., G–16278; L. L. ROBINSON, ET AL., G–16457; HUNT OIL COMPANY, G–16737; HASSIE HUNT TRUST, G–16763; PAN AMERICAN PETROLEUM CORPORATION, G–17028; MONSANTO CHEMICAL COMPANY, G–17519; THE ATLANTIC REFINING COMPANY, G–18572; T. L. JAMES & COMPANY, INC., G–19408; JACK W. GRIGSBY, OPERATOR, ET AL., G–19705; ROBERT F. ROBERTS, G–19810

ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 21, 1962)

*Syllabus**

1. In determining "in line" price for producer contracts herein, Commission considers contract prices prevailing during period such contracts were signed; *finding* "in line" price in North Louisiana was 16.5 cents until May, 1959 and 17 cents thereafter. P. 553.
2. Concluding proposed sales are required by public convenience and necessity at prices not in excess of 16.5 and 17.0 cents, Commission notes such price levels will not result in triggering of general price rises or an increase in United's existing rates by reason of "favored nation" clauses or otherwise. P. 553.
3. Commission requires refunds of amounts above permanently certificated rate with respect to the two producers whose temporary authorizations contained rate conditions. P. 554.
4. Commission *issues* certificates of public convenience and necessity under Section 7 of the Natural Gas Act. P. 554.

Robert M. Vaughan, Riley B. Fell, James D. Parriott, and *Harold L. Kennedy* for The Ohio Oil Company, Operator, et al.

William C. Blind and *Fred Simon* for Southwest Natural Production Company.

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*Initial decision appears on page 555. Rehearing and stay denied by order issued May 17, 1962, 27 FPC 991. Affirmed, 316 F. 2d 677 (CADC—1963).

Fred Simon and *William C. Blind* for James R. Nowery and B. M. Nowery, Jr.

Justin R. Wolf and *Charles A. Case, Jr.* for N. V. Kinsey and Norman V. Kinsey, Jr.

John M. Shuey for L. L. Robinson, et al.

Thomas G. Crouch and *Robert E. May* for Hunt Oil Company.

Thomas G. Crouch, Robert E. May, and *Richard F. Generelly* for Hassie Hunt Trust.

Norton Standeven, William J. Grove, John F. Jones, J. P. Hammond, and *C. O. Stone, Jr.* for Pan American Petroleum Corporation.

J. E. Howell and *Sam Pickard* for Monsanto Chemical Company.

Bernard A. Foster, Jr., Sherman S. Poland, and *Stuart J. Scott* for The Atlantic Refining Company.

William C. Blind for T. L. James & Company, Inc.

Thomas E. Stagg, Jr. for Jack W. Grigsby, Operator, et al.

William Greene and *Thomas E. Stagg, Jr.* for Robert F. Roberts.

C. Huffman Lewis, Vernon W. Woods, and *W. O. Crain* for United Gas Pipe Line Company.

Vincent P. McDevitt, Samuel G. Miller, and *Henry P. Sullivan* for Philadelphia Electric Company.

H. D. McHenry, William S. Tarver, and *Peter G. Smith* for Southern Natural Gas Company.

Bernard A. Foster, Jr. and *Robert Roberts, Jr.* for Arkansas Louisiana Gas Company.

William L. Brunner for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

The applicants listed in the caption are independent producers seeking permanent certificates for sales in North Louisiana to United Gas Pipeline Company which are now being made under temporary authorization. It appears that Pan American has already depleted the gas involved in Docket No. G–17028, and this docket will be severed from the present proceedings for such separate disposition as may be appropriate. The remaining applicants contend that certificates should be issued authorizing the 18.5 cent initial prices[1] in their respective contracts. In his initial decision, issued November 8, 1961, the examiner found, and we concur, that all questions relevant to the public convenience and necessity, except price, should be resolved in favor of granting the applications as filed. The applicants have excepted to the examiner's conclusion that the initial prices should be limited to 16.5 cents.

There is no evidence in the record to justify the 18.5 cent prices on the basis of costs. No conclusion whatever can be drawn from Hunt Oil Company's fragmentary "economic study" of its two production units involved herein, which purports to show costs of about 7 cents per Mcf for one unit and about $5.80 per Mcf for the other (now abandoned). The inferences made by Hunt from the proceedings in Docket No. G–9554, *et al.* and Docket No. G–9065, *et al.* are unwarranted since neither case considered the costs of the sales herein. The applicants' evidence as to increasing risks in North Louisiana was general in nature and cannot be translated into a specific level or range of costs for these sales.

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[1] All prices herein @ 15.025 psia, and exclusive of tax.

As a guide in determining whether each applicant's 18.5 cent price is "out of line," as that phrase is used in the CATCO decision,[2] the staff exhibit shows that during the period from June 1958 to October 1959, in which the 14 contracts involved herein were signed, 44 other contracts[3] were made for jurisdictional sales in North Louisiana at prices ranging from 12.5 cents to 18.5 cents per Mcf. Of the 29 sales made during the first eleven months of this period, 21 were priced at 16.5 cents, and 12 of these have been permanently certificated. Of the 15 sales made during the last six months, 8 were priced at 17.0 cents, and 2 of these have been permanently certificated. In 1958 three nonjurisdictional sales from the area were negotiated at prices from 18 to 19.5 cents; but from 1957 through 1960 only one jurisdictional sale has been permanently certificated at 18.5 cents. Assuming that the objections to considering this last sale are without merit, it is nevertheless apparent that the "in line" price in North Louisiana was 16.5 cents until May, 1959; and thereafter, it was 17.0 cents.[4]

The data found in the staff exhibit and elsewhere in the record indicates that the detailed provisions of the contracts referred to above are sufficiently comparable, without adjustments, for purposes of an initial price determination in a certificate case. Several of the applicants have suggested that the 16.5 and 17.0 cent prices, in contracts which provide 700 to 900 psig maximum delivery pressures, should be adjusted upwards for purposes of comparison with the 18.5 cent prices in United's contracts, which provide for 1,000 psig maximum delivery pressure. However, pressures of 700 to 1,000 psig are within the normal range of operation of high pressure pipelines: in the absence of a detailed study of the operating pressures of each of the various purchaser's pipelines, this adjustment is unsupported.

Considering the evidence of record in terms of the requirements of Section 7 of the Natural Gas Act, as defined by Court and Commission precedent, we conclude that the proposed sales are required by the public convenience and necessity at prices not in excess of 16.5 and 17.0 cents, as hereafter ordered. The approval of these price levels will not result in a triggering of general price rises or an increase in United's existing rates by reason of "favored nation" clauses or otherwise.[5]

The Commission finds:

(1) The proceedings in Docket No. G–17028 should be severed herefrom: the following findings do not apply to that docket.

(2) The applicants, independent producers of natural gas, are engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission, and each is, therefore, a "natural-gas company" within the meaning of the Natural Gas Act.

(3) The sales of natural gas hereinbefore described, as more fully described in the applications, are made in interstate commerce, subject to the jurisdiction of the Commission, and such sales, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

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[2] *Atlantic Refining Company* v. *F.P.C.*, 360 U.S. 378, 391 (1959); cf. *United Gas Improvement Company* v. *F.P.C.*, 283 F. 2d 817 (CA9 1960).

[3] This number does not include the California Company's 21.5-cent contract, dated October 10, 1958, which provides for a six-year deferral of the initial delivery.

[4] The price announced in the Commission's *Statement of General Policy No. 61–1* (issued September 28, 1960) for initial service in North Louisiana was 17.0 cents.

[5] See *Atlantic Refining Company* v. *F.P.C.*, *supra*, note 2.

(4) The applicants are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act, and the requirements, rules and regulations of the Commission thereunder.

(5) The subject sales of natural gas, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity, and certificates therefor should be issued as hereinafter ordered.

(6) It is necessary and appropriate in the administration of the Natural Gas Act that the initial prices for the subject sales of gas be prescribed as hereinafter ordered.

The Commission orders:

(A) The proceedings in Docket No. G–17028 are hereby severed from this proceeding.

(B) Permanent certificates of public convenience and necessity are hereby issued authorizing the services and sales respectively proposed by each of the remaining applicants, and the operations and construction necessary thereto, upon the conditions of the order.

(C) The certificates are issued herein with directions to the respective applicants to file within 30 days from the issuance of this order rate schedules providing the following initial base prices per Mcf at 15.025, psia plus 1.75 cents tax reimbursement, for natural gas sold and delivered to United Gas Pipe Line Company pursuant to the contracts here involved:

Applicant	*Docket No.*	*Base price*
The Ohio Oil Co., Operator, *et al*	G–15385	16.5 cents
Southwest Natural Production Co	G–15460	16.5 cents
James R. Nowery and B. M. Nowery, Jr	G–16190	16.5 cents
Norman V. Kinsey, Jr., *et al*	G–16278	16.5 cents
L. L. Robinson, *et al*	G–16457	16.5 cents
Hunt Oil Company	G–16737	16.5 cents
Hassie Hunt Trust	G–16763	16.5 cents
Monsanto Chemical Company	G–17519	16.5 cents
Atlantic Refining Company	G–18572	16.5 cents
Southwest Natural Production Co	G–19112	17.0 cents
T. L. James & Company, Inc	G–19408	17.0 cents
Jack W. Grigsby, Operator, *et al*	G–19705	17.0 cents
Robert F. Roberts	G–19810	17.0 cents

(D) Applicants L. L. Robinson, *et al.*, and The Atlantic Refining Company shall, within 60 days of the date on which this order shall become effective, refund to United with 6 percent interest the respective amounts collected from United in excess of 16.5 cents per Mcf at 15.025 psia plus tax reimbursement for volumes delivered to United under the subject contracts from the date of initial delivery to United until the effective date of this order.

(E) Within 10 days of the date of refund provided in Paragraph (D), above, L. L. Robinson, *et al.* and The Atlantic Refining Company shall each file with the Commission an officially certified statement showing the amount of the refund, its manner of computation, and the interest payments related thereto, and a statement from United acknowledging the receipt.

(F) The certificate issued to each applicant is not transferable and shall be effective only so long as the applicant continues the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act, and the applicable rules, regulations, and orders of the Commission.

(G) The grant of the certificate to each applicant herein is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against such applicant.

DECISION

UPON APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING SALES OF NATURAL GAS

(Issued November 8, 1961)

KELLY, *Presiding Examiner*: The parties named in the above caption have all filed applications for certificates of public convenience and necessity authorizing them to make sales of natural gas for resale in interstate commerce to United Gas Pipe Line Company (United) from production in North Louisiana. United owns and operates a pipeline for the transportation and sale of natural gas for resale in interstate commerce. Each Applicant has obtained from the Commission temporary authorization to make the sale covered by his application and each has delivered gas into the pipeline of United pursuant thereto.

Each Applicant except Pan American Petroleum Corporation (Pan American) seeks a permanent certificate authorizing his sale to United. Counsel for Pan American announced at the opening of the hearing that his company had delivered natural gas pursuant to the temporary authorization given by the Commission but that the gas contracted to be sold to United had become "depleted"; and that, therefore, Pan American would not offer testimony but would rely upon that presented by the other Applicants. There was no further participation in the hearing by Pan American and it filed no brief. United, the purchaser, has not challenged the statements made by counsel for Pan American, nor has the Commission staff nor any intervener. In view of the information given to the record by counsel for Pan American, no permanent certificate could issue to it; but the temporary authorization issued to Pan American by the Commission in Docket No. G–17028, which is still outstanding and in effect, should be properly terminated by order of the Commission. Section 7(b) of the Natural Gas Act (Act) requires that a natural gas company obtain the permission and approval of the Commission before abandoning any sale being made pursuant to temporary authorization from the Commission. Pan American has not sought such permission and approval. In the circumstances, no action is here taken upon Pan American's application, but it is referred to the Staff of the Commission for such action as it may deem advisable in view of the outstanding temporary authorization issued, as aforesaid, to Pan American. When the Applicants are hereinafter referred to collectively, the reference will not include Pan American.

Each Applicant has filed with the Commission a rate schedule covering the sale of natural gas here involved. Each such schedule calls for the payment of the initial base price of 18.5 cents per Mcf, provided by the contract with United, with the exception of those filed pursuant to temporary authorizations from the Commission which imposed a condition lowering the contract base price to 17.0 cents per Mcf. Appendix A hereto is a list of all Applicants and dockets in these consolidated proceedings, with the dates of the respective contracts with United and of the temporary authorizations from the Commission, and with the base price now being collected pursuant to the terms of such authorizations. In addition to the base price per Mcf, United is required to make reimbursement of a severance tax of 1.75 cents per Mcf to the seller of the natural gas. Thus, United is required by the gas purchase contracts here involved to pay 20.25 cents per Mcf.

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Eight of the sales here involved are of gas produced in the Ada Area of Bienville Parish and the sellers and docket numbers are as follows:

The Ohio Oil Company, *et al.* (Ohio)	G–15,385
Southwest Natural Production Company (Southwest)	G–15,460
James R. Nowery & B. M. Nowery, Jr. (Nowerys)	G–16,190
L. L. Robinson, *et al.* (Robinson)	G–16,457
Hunt Oil Company (Hunt Company)	G–16,737
Pan American Petroleum Corporation (Pan American)	G–17,028
Monsanto Chemical Company (Monsanto)	G–17,519
The Atlantic Refining Company (Atlantic)	G–18,572

The Applicants, Norman V. Kinsey, *et al.*, (Kinsey) Docket No. G–16278, and Hassie Hunt Trust (Hunt Trust), Docket No. G–16763, have their production in the Bryceland Area of the Bear Creek-Sailes Field in Bienville Parish. Applicant Jack W. Grigsby, Operator, *et al.* (Grigsby), Docket No. G–19705, produces gas from the Bear Creek Field of Bienville Parish.

The Applicants, Southwest Natural Production Company (Southwest), Docket No. G–19112, and T. L. James & Company, Inc. (James), Docket No. G–19408, have their production in the Calhoun Field of Ouachita Parish. Applicant Robert F. Roberts (Roberts), Docket No. G–19810, produces gas in the Simsboro Area in Lincoln Parish.

The Commission permitted intervention by United, Southern Natural Gas Company (Southern), The Philadelphia Electric Co. (Philadelphia), and the Arkansas Louisiana Gas Company (Arkansas). The first three named interveners actively participated in the hearing and have filed briefs. After being granted intervention, Arkansas filed a formal pleading by which it gave notice of the withdrawal of its petition to intervene. United supported all applications for certificates and it has urged by brief that they all be granted without condition. Philadelphia opposes all applications and urges the attaching of price conditions if certificates are issued. Southern opposes only the application of Jack W. Grigsby, Operator, *et. al.* (Grigsby), Docket No. G–19705 and urges that if a certificate is granted to this Applicant, a condition should attach to it requiring a considerably lower initial price.

All of the dockets shown in the above caption were consolidated by notice of the Secretary of the Commission of January 21, 1960, after there had been issued to all Applicants temporary authorizations to make the sales called for in their contracts with United, and a hearing upon the applications was set by this notice for April 11, 1960. Upon requests made by certain Applicants, there were two postponements of the hearing, which was finally begun on September 6, 1960, and concluded on November 17, 1960, after five days of hearing. Testimony and exhibits in support of the applications were received from the Applicants and from United. The Staff of the Commission presented evidence in support of its position that the certificates should be conditioned so as to lower the initial prices. Southern presented testimony in support of its position stated above in regard to the application of Grigsby in Docket No. G–19705. Philadelphia offered the testimony of an expert witness, together with an exhibit, in opposition to the applications, but the evidence was rejected by the Presiding Examiner because it was objectionable in form.

Initial briefs were received from the Applicants and United in support of the applications. Opposition briefs were received from the Staff, Philadelphia and Southern. Final reply briefs were received from the Applicants and United on April 17, 1961. A joint initial brief (Joint Brief) was filed in behalf of all Applicants except Kinsey, Monsanto and Atlantic which filed separate initial briefs.

Kinsey and Atlantic also filed separate reply briefs; but Monsanto joined in the Joint Reply Brief filed by all other Applicants. Grisby joined in both joint briefs, and also filed a separate reply to the brief filed by Southern.

Upon the basis of the record, it is found that the natural gas proposed to be sold by the Applicants is now being sold and delivered to United for transportation and resale in interstate commerce. The Commission has issued to United budget-type certificates, under which it has constructed and is operating the necessary facilities to receive into its pipeline the gas being sold to it by the Applicants, under their temporary authorizations from the Commission. It is found that the natural gas here involved is needed by United to meet its present and future consumer demands, although such need was not urgent at the time United entered into the contracts with the Applicants here under consideration. There is but one real issue here, namely, whether the Applicants have sustained their burden of proof to show that the public convenience and necessity require that permanent certificates should be issued to the Applicants authorizing their proposed sales to United at the initial base price of 18.5 cents, plus present tax reimbursement of 1.75 cents, for a total initial price of 20.25 cents per Mcf.

It is specifically found that the Applicants are "able and willing properly" to supply, sell and deliver, natural gas to United pursuant to their respective contracts, and "to conform to the provisions of the Act and the requirements, rules and regulations of the Commission thereunder." It is also found that the proposed sales of natural gas by the Applicants to United, at some initial price probably not excessive, are and will be "required by the present or future public convenience and necessity." Therefore, it must be determined upon the basis of this record whether the Applicants have sustained their burden of proof and have established by substantial evidence that their initial price under their contracts of 20.25 cents, including severance tax reimbursement, is required by the public convenience and necessity to be authorized in these consolidated certificate proceedings. If they have failed to sustain this burden, the applications should either be denied or the issued certificates should be conditioned at a lower initial price.

The Issue and the Law

In making a determination of the aforesaid single issue, it is imperative that one look first for a fair measure by the public interest of an initial rate to be authorized in the certification by the Commission of a sale of natural gas in interstate commerce under Sections 7(c) and 7(e) of the Act. What formula is to be applied in determining the amount of the initial price that "is or will be required by the present or future public convenience and necessity," in the sense of the Act? The Courts have made it very plain that the conditioning of a certificate authorizing a sale, so as to make the initial lawful rate less than the contractual initial price, is lawful when done to protect the consuming public against what may be an excessive rate while the justness and reasonableness of such contract price is being determined in a different proceeding under Sections 4 and 5 of the Act.[1] It may be said, therefore, that the public convenience and necessity require that the protection of the consuming public should be such as to make reasonably certain that no excessive rate be imposed upon it during the period necessary for the conducting of a rate proceeding, wherein all relevant evidence may be considered in relation to standards and formulas by which a determination may be made of the justness and reasonableness of the contractual price.

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[1] Atlantic Refining Co. v. F.P.C. *et al.*, 360 U.S. 378, 392 (Catco) Texaco, Inc., *et al.*, v. F.P.C., 290 F. 2d 149. (Texaco).

The Courts have said also that no meticulous application of rate-making standards and formulas need be made in a proceeding upon an application under Section 7 of the Act for a certificate authorizing a sale of natural gas.[2] In discussing the importance of a "most careful scrutiny and responsible reaction to initial price proposals of producers under § 7" by the Commission, the Supreme Court held in Catco that "a permanent certificate should not be issued" whenever the record in a certificate case "signals the existence of a situation" concerning an initial price proposal of a producer "that *probably* would not be in the public interest."[3] It may be logically inferred from this quoted language that the Commission may attach a rate condition to the certification of a sale of gas whenever the record in the proceeding discloses the mere probability of the excessiveness of a proposed rate. If no standards of rate making are to be applied in a certificate case, nothing more than the probability of unlawfulness, because of excessiveness, is possible of determination.

It is concluded, therefore, that whenever the situation reflected by the record of a certificate proceeding is such as to show the *probable* excessiveness of a producer's initial price proposal, it is the duty of the Commission to protect the consuming public either by denying the certificate applied for, or by conditioning it at a lower rate which is *probably* not excessive. This lower rate may be a judgment figure based upon the entire record. In this manner is accomplished the principal aim of the Act, namely, to protect the consuming public against exploitation; and the requirements of public convenience and necessity are met.

The independent producer who makes a contract for the sale of gas for resale in interstate commerce, has no vested right under the Act to collect his contractual initial price. He cannot legally begin deliveries under his contract until the Commission has temporarily authorized or certificated his sale either at the initial price provided in the contract or at a price at a lower level deemed necessary to protect the public interest. If the Commission so lowers his contractual initial price, he has the right to reject the permanent certificate tendered to him, unless he has begun delivery under his contract pursuant to temporary authorization from the Commission. Having the contractual right, as between himself and the buyer, to receive the contractual initial price, the producer may accept the Commission's certificate, by which the initial rate is lowered, file with the Commission his rate schedule calling for the lower rate, and then immediately file a proposed change in rate, under Section 4(d) of the Act calling for his contractual initial price.[4] As a regulated natural gas company he then has the right to obtain an adjudication by the Commission of the issue of the lawfulness of his proposed change in rate in the sense of Section 4(a).

Inasmuch as the independent producer has this right, under the Act, to a later determination of the issue of the lawfulness of his contractual initial price, it would appear to be quite futile to apply the complex standards, formulas, or criteria, used in measuring for lawfulness a rate for a sale by a producer, in a certificate proceeding under Sections 7(c) and 7(e). The problem of determining the lawfulness of an independent producer rate has been judicially said to be "a difficult one at best."[5] The finding of the Commission in such a certificate proceeding is only that the rate certificated is required by the public convenience and necessity; and if it be a lowered rate, its certification is in no sense an adjudication that the contractual initial price is unjust and unreasonable. Such

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[2] Catco and Texaco.

[3] Emphasis added to Catco quotation.

[4] Texaco and Catco.

[5] Bel Oil Corporation v. F.P.C., 255 F. 2d 548, 553; Forest Oil Corporation v. F.P.C., 263 F. 2d 622, 625.

an adjudication is not necessary under the Act in order to lower the contractual price in a certificate proceeding. It must be remembered that there may be numerous factors, in addition to initial price, to be considered in making a determination, under Section 7 of the Act, of whether a sale of gas is required by the public convenience and necessity. If there is to be an early decision upon an application for certification of a sale of gas, it cannot be made into a rate proceeding as well as a certificate proceeding.

It is quite understandable why the independent producer seeks vigorously to have his sale certificated at the contractual initial price. If it be so certificated, he is given a decided advantage over the consuming public, in that his rate may not be attached except in a lengthy proceeding under Section 5(a) of the Act, as explained in Catco. During the pendency of such proceeding, he collects his contractual price without any possibility under the Act of the consuming public ever recovering any excessive part thereof. It is to protect against this that the Supreme Court has said that the Commission may lawfully lower a proposed initial price when certificating a jurisdictional sale whenever such price appears to be *probably* excessive. A reading of the cases in the appellate courts concerning the propriety of attaching rate conditions to certificates, leaves no doubt that the Commission is not required under the Act, to make a meticulous measuring of a proposed price in a certificate proceeding, and it need only consider the probability of its lawfulness.[6]

The independent producer has the right under the Act to enter into a contract for the sale of natural gas at an agreed price. However, such price and other provisions of the contract are subject to review by the Commission.[7] In making such a review the Commission must endeavor to balance producer and consumer interests. Such a balancing cannot be accomplished fairly and satisfactorily without making a determination of whether the contractual rate is just and reasonable in the sense of Section 4(a) of the Act. This section of the Act gives the only measure of lawfulness for a rate for a jurisdictional sale of gas. In exercising its authority to review a proposed initial price for a sale, it would appear indeed to be advisable for the Commission to bring about a determination of the lawfulness of such price as quickly as possible. Such determination cannot lawfully be made in a certificate case under Section 7 of the Act; and the sooner a rate proceeding under Sections 4 and 5 can be instituted the more quickly will such determination be made.

It will be entirely impossible for such a determination to be made at an early date after application is filed for a certificate authorizing a producer sale, if both the certificate proceeding and the rate proceeding are to be encumbered by the complexities encountered in measuring independent producer rates so as to attain a balancing of producer and consumer interests. One of the obvious and most important purposes of the Act is not to treat unfairly either the consuming public or the producer. The producer will always feel that he is entitled to the price for which he has bargained in the open market. But the Act says that all rates must be regulated as provided therein. If the Commission believes that there is probability of the proposed initial price being unjust and unreasonable, it has the authority and positive duty, in a certificate case, to lower the proposed initial price pending the institution and completion of a rate proceeding in which the contractual price may be properly measured and regulated so as to treat unfairly neither the consuming public nor the producer. If such rate proceeding is then had, the true measure of what the producer is entitled to as a lawful rate

[6] Catco and Texaco.

[7] United Gas Pipe Line Co. v. Mobile Gas Service Corporation and F.P.C., 350 U.S. 332.

may be arrived at by lawful rate-making criteria, which should truly balance his interests and those of the consuming public.

There are, and always will be, controversies between the producer and the consumer concerning the rates for the sale of natural gas in interstate commerce; and the deciding of such controversies is one of the functions of the Commission under the Act. Such decisions should be made with complete objectivity and with the dual aim of preventing the exploitation of the consumer and providing a fair return to the producer in the operation of his business. As pointed out hereinbefore, the consumer may be protected from exploitation by the imposition of a rate condition upon the certificate authorizing the producer to sell gas in interstate commerce, whenever there exists the probability of excessiveness of the producer's proposed initial price. There should likewise be a way of protecting the producer against loss in the event that his contractual initial price is found ultimately by the Commission in a rate proceeding to be just and reasonable after having been reduced by a conditioned certificate.

When a producer has on file with the Commission a lawful rate schedule, and then files a notice of an increased rate, which is made pursuant to the price provisions in his contract of sale, such proposed increased rate may not become effective for 30 days unless the Commission allows it to become effective sooner. In fact, the notice of the increased rate must be given at least 30 days prior to the proposed effective date thereof. During this period of 30 days the Commission may suspend the proposed increased rate for a period of not more than five months from the proposed effective date of such rate, after the expiration of which the increased rate may become effective, on motion of the producer, subject to the requirement that he make refund of any portion of such increased rate found not justified by decision of the Commission. The length of the period of the suspension of the increased rate, not to exceed five months, is a matter within the discretion of the Commission. The length of such suspension may be as little as one day. In the rate proceeding, the producer is not prevented from collecting his full contractual price, subject to refund as aforesaid, except during the 30 days required for the notice of change in his rate, and during the period of the suspension thereof. If his contractual price is ultimately found to be just and reasonable, he loses the difference between his existing filed rate and the proposed increased rate during both the period of notice and the period of suspension.

There is no way, under the Act, of avoiding such loss in said two periods when the producer seeks to increase a rate which is being collected under a rate schedule lawfully on file with the Commission. It is the apparent legislative intent that the natural gas company not be permitted to collect an increased rate during said two periods even under bond. However, it is within the statutory power of the Commission to make the period of suspension as short as it deems equitable in the circumstances presented by the record before it. Where the Commission attaches a rate condition to a certificate authorizing a sale of gas by a producer, it may well in proper circumstances recognize in its certificate order the right of the producer to file immediately, under Section 4(d), a schedule calling for an increase of his conditioned rate to the level of his contractual initial price. Of course, the 30-day notice of such change in rate must be given "to the Commission and to the public" as required by Section 4(d). The certificate may well also provide, in proper circumstances, that if the producer exercises such right and makes such filing under Section 4(d), the operation of his schedule for the increased rate will be suspended by the Commission, under Section 4(e), for a period of only one day.

If the producer does exercise such right, then, after the period of notice and the short period of suspension, he loses no part of his contractual price except such part as may be ultimately found not to be justified by the Commission decision in the rate proceeding. The consuming public is protected against exploitation, first, by the attachment of the rate condition to the certificate in the manner described above, and later, by the requirement that the producer furnish bond to refund any part of the contractual price found not to be justified; and the possibility of loss by the producer of any lawful portion of his contractual price is limited to that which may occur during the 31 days of the notice period and the short suspension period combined. By following such procedure, there will occur an earlier determination of that inevitable issue of whether the producer's contractual price is just and reasonable by rate-making standards and formulas and, if it is not, what is the lawful rate he is entitled to collect from the consuming public.

In the unanimous opinion of the Court of April 14, 1961, in the Texaco case,[8] which involved a rate conditioned certificate of the Commission, it was said:

> However, we think it appropriate to say that we find no authority for holding that a producer does not have the right immediately to file a proposed rate increase of 20 cents per Mcf after complying with the condition that it file a new schedule carrying an initial price of 17.7 cents in lieu of the 20 cent rate in the contract. (Slip Copy, p. 14)

This quotation is given in support of the position taken above that a rate proceeding, under Sections 4 and 5 of the Act, is inevitable any time that a contractual initial price is reduced by a rate condition attached to a certification of a jurisdictional sale of gas, if the seller pursues his right, as a regulated natural gas company, to have a determination made of whether his contractual price is a just and reasonable rate in the sense of Section 4(a) of the Act. If a rate case is inevitable, it is so utterly futile to waste time in a certificate case by receiving the type of financial evidence that is absolutely necessary as a basis for a determination of whether a contractual initial price is just and reasonable in such sense. And yet, what other than a just and reasonable rate is, in the ultimate, required by the public convenience and necessity? Therefore, it is found that in this, and in other similar certificate cases, where there remains for decision only the single issue discussed above, and where a price condition is indicated by the record, the public convenience and necessity require that an order be entered fixing the certificated rate sufficiently low to protect the consuming public against exploitation, and prescribing the procedures outlined above, for the protection of the rights and interests of the producer applicants. Such order should be supported by a finding that such procedures are required by the public convenience and necessity.

Keeping in mind the great number of cases pending, and to be pending, before the Commission in which certification of jurisdictional sales is sought, the public convenience and necessity indeed require that such procedure be adopted Where there is no doubt of the propriety of certificating a sale except in relation to initial price, it should be possible to dispose quickly of the certificate case and to enter upon a rate case in such manner as to protect both the producer and the consumer against any unnecessary loss. While any decision in a proceeding under Section 7 of the Act must be based entirely upon the requirements of the public convenience and necessity, it may indeed be decided in the certificate case that the public interest definitely requires the procedures herein prescribed

[8] Texaco.

as a means of shortening the administrative process—most frequently entirely too long—and at the same time preserving and protecting the rights of all.

The Applicants here are hereinafter given the opportunity to have a balancing of their interests with those of the consumer, in the manner above discussed. It is found upon the basis of the record that the Applicants have not sustained their burden of proof to show that the public convenience and necessity require that their proposed sales of natural gas should be certificated at the rate provided in their contracts of 20.25 cents per Mcf, including severance tax. The certification of the sales here involved is not denied but it is made with a rate condition attached. The amount of the lower rate here certificated is arrived at in the manner hereinafter shown, and no attempt is here made to measure such lower rate by the standards and formulas used in rate proceedings to measure the lawfulness of a rate in the sense of Section 4(a) of the Act. There is, in fact, in the record here no evidence by which such measure could be made.

It is deemed justified in these consolidated proceedings that the condition attached to the certificate here issued, requiring a rate lower that the contractual price, should include a recognition of the right of the Applicants to file for their contractual initial price under Section 4(d) immediately after the proper acceptance of, and compliance with, such certificate. It is justified also that there be attached to the acceptance by the Applicants of such certificate the condition that if and when such rate filing is made by the Applicants, the operation of the new rate schedule will be suspended by the Commision, under the provisions of Section 4(e), only for one day from its proposed effective date, after which the Applicants may move that the contractual initial price go into effect immediately upon the Applicants furnishing bond to refund any part thereof found not justified by the Commission decision following a hearing concerning the lawfulness of such rate.

The Evidence

The record evidence consists of testimony with exhibits, and of documents received by reference to them in the files of the Commission. Officers or representatives of 10 of the 12 Applicants who participated in the hearing, appeared as witnesses. A Vice-President of United testified in support of the applications. A Supervising General Engineer of the Commission gave testimony with an exhibit showing initial rates for sales of gas in North Louisiana which had been certificated or temporarily authorized by the Commission, for which the basic contracts were executed in 1957, 1958 and 1959. Southern, an intervener, presented testimony in opposition to but one application, namely, that of Jack W. Grigsby, Operator, et al., Docket No. G–19705. Southern's position is discussed separately hereinafter. The facts herein found are based upon this record evidence.

Before discussing the evidence in detail, as it relates to the single issue for decision, certain specific findings should be made of facts which appear to be uncontroverted. There is no affiliation whatever between United and any of the Applicants, and all negotiations for the contracts here involved are found to have been conducted at arm's lgneth. No prices being paid for gas by United will be "triggered" by the provisions of the contracts here, but this is not a finding that the contracts here do not affect the prices in subsequent contracts for the purchase of natural gas in North Louisiana, a matter hereinafter discussed.

United's brief speaks of its "main line high pressure 20" and 24" looped lines extending from the Carthage Field in East Texas to a point near Monroe, Louisiana," adjacent to which are located the five areas or fields producing the natural gas here involved. The gas in the Ada Area of Bienville Parish became available in 1958, and in "early April" of that year United began negotiations to obtain some of this "new gas" from The Ohio Oil Company (Ohio), one of the principal owners of natural gas in the Ada Area. United sought this gas to increase its reserves to which it was continually adding to meet its consumer demands. It is United's position that the Carthage Field has been declining in delivery capacity for some years, due to the large quantities of gas withdrawn therefrom, and the company needed sources of supply in new areas to help offset its withdrawals there. The practice of continually adding reserves in this manner is a part of the company policy of United. United is a large interstate pipeline company with a consumer demand in excess of 1.3 billion cubic feet of gas per annum. It is found specifically that United had no such urgent need for the natural gas here involved as would justify the payment by it of two cents more per Mcf than was being paid in North Louisiana in 1958 by any other interstate pipeline company, as hereinafter shown.

United's "Established" Price

The negotiations between United and Ohio resulted in the contract executed by them on June 10, 1958, by which the initial base price of 18.5 cents per Mcf was agreed upon. Thereafter, negotiations were had with other owners of gas, including certain Applicants here, whose production was in the Ada Area, and United made contracts with them also at 18.5 cents per Mcf. By the execution of these gas purchase contracts the price of 18.5 cents per Mcf became "established for gas to be purchased for the high pressure main line between Carthage (Field) and Monroe", according to the testimony of United's Vice President; and contracts were then made at this price in other areas of North Louisiana adjacent to said main line. United agreed in all of these contracts to pay the existing Louisiana severance tax which amounts to 1.75 cents per Mcf, making the total price to United of 20.25 cents per Mcf. The dates of execution of all of these contracts here involved are shown in Appendix A hereto. Deliveries were first made, under the contracts of earlier date, on January 29, 1959; and the dates of commencement of subsequent deliveries followed respectively the dates of the temporary authorizations shown in Appendix A.

Comparisons by Applicants

The Applicants presented no evidence concerning the prices which were being paid for natural gas in North Louisiana in "early April" 1958, when United began its first negotiations with Ohio which resulted in a gas purchase contract providing for 18.5 cents per Mcf. There is a controversy here as to whether this price is "in line" or "out of line" with other prices paid in North Louisiana. The Applicants introduced evidence only of certain selected prices contracted for in 1958 and 1959, for both jurisdictional and non-jurisdictional sales, with which, they claim, their price is "in line" and all of these are discussed hereinafter. The price which United "established" for gas to be received into its pipeline, and the selected prices aforesaid, are all higher than any prices that were being paid in North Louisiana in 1957 and early 1958, so far as is shown by this record. The fact that the price of 18.5 cents was agreed upon after bargaining by the parties at arm's-length in the open market, does not establish that this price is just and reasonable, or that it is required by the public convenience and necessity to be certificated as the initial rate. Quite to the contrary, these increased prices

indeed indicate or signal that they should be scrutinized with care to determine whether they are justified in any sense of the provisions of the Act.

The Staff's Exhibit

The Commission Staff has presented an exhibit which sets forth certain provisions, including the purchase price, of the contracts of the Applicants, and of other contracts for jurisdictional sales of natural gas in North Louisiana which were executed in 1957, 1958 or 1959. The sales provided for in these other contracts had all been either permanently certificated or temporarily authorized by the Commission before September 6, 1960, the date upon which the hearing began in these proceedings. Including the contracts of the Applicants here involved the Staff exhibit shows 77 sales so authorized. With the exception of the sales to United at its "established price" of 18.5 cents, there were only nine contracts listed in this exhibit for prices in excess of 16.5 cents per Mcf. Of these nine, eight provide for a price of 17 cents and one for 21.5 cents per Mcf. The price of 21.5 cents was for gas not planned to be delivered for some six or seven years after the date of the contract, October 10, 1958, and this is discussed separately hereinafter as a price with which the Applicants claim their price to be "in line". The eight contracts for a base price of 17 cents were all executed between June and October of 1959 and seven of them are for gas produced in the Calhoun Field in Ouachita Parish, in which United has contracted to pay 18.5 cents under three contracts which were executed in July and August, 1959. Two of said three contracts last mentioned are with Applicants here and are involved in these proceedings.

The Staff exhibit shows that 28 sales were authorized by the Commission in the period covered at a base price of 16.5 cents. Three of these sales contracts were executed in 1957, 11 in 1958 and 14 in 1959. In these three years there were six contracts executed for prices between 14 and 16 cents, and there were 18 contracts for less than 14 cents. The Staff exhibit does not include any contracts executed in the period which called for less than 12 cents per Mcf. The contract prices discussed above as being taken from the Staff exhibit are all base prices which are exclusive of the severance tax.

The evidence shows that in early 1958 the highest base price being paid in North Louisiana by an interstate pipeline company for natural gas was 16.5 cents per Mcf. In June of 1958 and the immediately following months, United "established" a price for its pipeline in this area 2 cents higher than such highest price. The Staff's exhibit shows that the next highest price being paid by an interstate pipeline company, as of September 6, 1960, was 17 cents, and no contract for this price was entered into prior to June 18, 1959. United entered into 16 contracts with producers in North Louisiana at the price of 18.5 cents, between June 10, 1958, and October 14, 1959. Each such contractual price is, of course, "in line" with the other 15; but each is as well "out of line" with every other price being paid by an interstate pipeline company in North Louisiana. The certification of United's "established" pipeline price as an initial rate certainly cannot be said to be required by the public convenience and necessity merely because United has executed contracts for this price with 16 sellers in North Louisiana, of whom all except two are Applicants here.

The Competition in North Louisiana

In his discussion of the negotiations between United and Ohio leading to their contract of June 10, 1958, United's Vice President made the statement that "United was aware of other offers for gas in this area, including not only offers being made by interstate pipeline companies, but offers being made by industrial consumers desiring to purchase gas in the North Louisiana area and having

it transported to their own markets." To this he later added that "United felt that the 18½ cent price which United made with Ohio at Ada was the lowest price at which United could buy this gas." The evidence of the Applicants establishes that there are six major interstate pipeline companies within a radius of about ten miles from the Ada area. The evidence establishes that at least five of these companies evinced an interest in purchasing the gas in this area. The record does not establish that the location of the natural gas reserves acquired by United was any more advantageous to it than to any other of these pipeline companies. However, there is no evidence in this record of any other pipeline company having made a specific offer of more than 16.5 cents for such gas prior to the date of United's contract with Ohio of June 10, 1958. There is testimony to the effect that United started negotiations with Ohio at a price of 17 cents. Furthermore, there was no other sale to an interstate pipeline company above 16.5 cents per Mcf in North Louisiana until June 18, 1959, when the first of several contracts were made at 17 cents.

From the evidence contained in the Staff exhibit, it may be most logically concluded that it "probably would not be in the public interest" to issue permanent certificates authorizing these sales to United at the initial base rate of 18.5 cents per Mcf. This price was 2 cents higher than any price being paid for present deliveries in North Louisiana by any interstate pipeline company at the time it was "established" by United in 1958. It remained 2 cents higher than any such price until June 18, 1959, when the first sale at 17 cents was made in North Louisiana to a pipeline company; and it then became higher by 1½ cents instead of 2 cents per Mcf. And it has so remained, at least until September 6, 1960, the date upon which the hearing began in these proceedings. It must be remembered also that 11 gas sales contracts were made to interstate pipeline companies in North Louisiana in 1958 at 16.5 cents per Mcf, and that 14 such were made in 1959. It is found, on the basis of the record now before the Commission, that any price for gas in a jurisdictional sale in North Louisiana above 16½ cents per Mcf was suspect in 1958 when temporary authorizations for sales at 18½ cents were first issued to some of the Applicants here. On the basis of all the evidence, such price is still suspect and definitely signals that it should not be permanently certificated as an initial rate.

It is true, no doubt, that the provisions in the 77 contracts reflected in the Staff exhibit vary to some extent. However, there is no showing made in this record that the contracts of the Applicants contained provisions so advantageous to United as to warrant its paying 2 cents more per Mcf than any offer made by any of the other six interstate pipeline companies, said by the Applicants to be within a radius of 10 miles of the Ada Field gas. By making the contracts to purchase this "new gas" which was adjacent to its pipeline, United acquired some considerable quantities of natural gas*; but the other six pipelines in the area did not see fit to offer more than 16.5 cents per Mcf for such quantities of gas at the time the price of 18.5 cents was established by United in 1958, so far as this record shows.

Contentions of Applicants

The briefs of the Applicants seek to justify the permanent certification of their sales to United at 18.5 cents per Mcf upon various grounds. Important among

*The estimates by United of the dedicated reserves were: Ada Area, 42 billion cubic feet; Bear Creek-Sailes Area, 5 billion; Bear Creek Area, 6 billion; Simsboro Area, 11 billion; and Calhoun Area, 10 billion. Counsel for Ohio said in an opening statement, at the beginning of the hearing, that the quantities of gas here involved "while in themselves perhaps are not great quantities, are significant for the North Louisiana market." Tr. 6

these is the contention of the Applicants that their said price is not "out of line." It has been pointed out above that the price of 18.5 cents "established" by United is definitely quite "out of line" with about 60 prices agreed upon in contracts executed in the calendar years of 1957, 1958 and 1959, for the sale of gas to interstate pipeline companies in North Louisiana. One brief of the Applicants asserts, concerning the price of 18.5 cents, that "Comparable jurisdictional gas is being sold under permanent certificate authorization at this price, nonjurisdictional gas is being sold in excess thereof." All of such sales cited by the Applicants have been given consideration and are hereinafter discussed.

United's Sixteen Contracts

It is shown hereinbefore that United has entered into 16 contracts to purchase gas in North Louisiana at its "established" price of 18.5 cents per Mcf. Fourteen of the dockets covering respectively the applications to the Commission for authority to make these sixteen sales were consolidated for hearing by the Commission order of January 21, 1960, discussed above. In one of the other two such dockets, G–19209, the Commission, on September 3, 1959, issued a temporary authorization to Union Producing Company (Union) to make the sales called for by its contract with United, at the price of 18.5 cents per Mcf. By letter of September 4, 1959, Union accepted said temporary authorization subject to the conditions therein stated. The gas so authorized to be sold by Union is produced in the Calhoun Field in Ouachita Parish. No further action has been taken in Docket No. G–19209. In the other of the two aforesaid dockets, not consolidated with these proceedings, the Commission, on July 8, 1959, issued to Gulf Oil Corporation (Gulf) a permanent certificate in Docket No. G–16745, authorizing the sale of gas under its contract with United at the initial rate of 18.5 cents per Mcf, exclusive of Louisiana tax.

There is no explanation in the record of why Docket No. G–19209, covering said sale by Union to United was not consolidated with the other 14 dockets here involved. The natural gas involved is produced in the Calhoun Field of Ouachita Parish, just as is the gas in Docket Nos. G–19112 and G–19408, which are consolidated in these proceedings. These two consolidated dockets cover contracts with United, both of which are dated July 10, 1959, and the Union contract with United was dated August 5, 1959. Temporary authorizations had issued in all three of these dockets well in advance of the Commission's consolidation order of January 21, 1960, two in September and one in October 1959. No conjecture is here made as to the reason for the omission of Docket No. G–19209 from the consolidation here; and the contract involved is discussed only because it is shown by the Staff's exhibit to be one of the 16 contracts made by United with producers in North Louisiana. The temporary authorization in this docket of the price of 18.5 cents per Mcf, left without further action upon it since it issued on September 3, 1959, has no probative force with relation to the single issue here presented.

The Certification of the Gulf Sale

Each brief filed by the Applicants stresses the fact that a permanent certificate was issued to Gulf by the Commission on July 8, 1959, authorizing the sale of gas to United at 18.5 cents per Mcf. It is argued by them that the Gulf sale is of gas produced from the Ada field of Bienville Parish, just as are 8 of the 14 sales here involved, and that their contractual initial price being the same, should be permanently certificated by the Commission, as was Gulf's rate. There is evidence to the effect that Gulf would not begin the delivery of gas to United until its sale was permanently certificated by the Commission; and it was so certificated more than 6 months before the consolidation order of January

21, 1960, covering these proceedings. The Gulf rate is, of course, one of the prices selected by the Applicants to show their rate not to be "out of line."

Gulf is a large integrated oil company which makes sales of natural gas in interstate commerce under numerous contracts. On February 12, 1959, the Commission issued an order which instituted a rate investigation against Gulf in Docket No. G–17813, and which consolidated with said docket 43 then pending rate cases of Gulf and Gulf (Operator). These consolidated proceedings may be identified by Docket No. G–9520, et al. The consolidation was made upon Gulf's motion, in which it was stated "that the evidence it proposes to present at the hearing commencing February 17, 1959, is on a company-wide basis, and would be in support of proposed increases in all dockets, those proposed to be consolidated as well as those now consolidated." Gulf's sale to United is covered by its Rate Schedule No. 147 which is definitely under consideration in the Gulf rate proceeding.

In said order of consolidation it was found:

> (2) It is necessary and proper in the public interest and to aid in the enforcement of the provisions of the Natural Gas Act that an investigation be instituted by the Commission, upon its own motion, into and concerning all rates, charges, or classifications demanded, observed, charged, or collected by Gulf Oil Corporation in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, and any rules, regulations, practices, or contracts affecting such rates, charges, or classifications.

In the said order the Commission ordered:

> (A) An investigation of Gulf Oil Corporation is hereby instituted under the provisions of the Natural Gas Act, particularly Sections 5 and 15 thereof, for the purpose of enabling the Commission to determine whether, with respect to any transportation or sale of natural gas, subject to the jurisdiction of the Commission, made or proposed to be made by Gulf, any of the rates, charges, or classifications demanded, observed, charged or collected, or any rules, regulations, practices, or contracts affecting such rates, charges or classifications are unjust, unreasonable, unduly discriminatory, or preferential.
>
> (B) If the Commission, after a hearing has been had, shall find with respect to Gulf that any of its rates, charges, classifications, rules, regulations, practices, or contracts, subject to the jurisdiction of the Commission are unjust, unreasonable, unduly discriminatory, or preferential, the Commission will thereupon determine and fix by order or orders just and reasonable rates, charges, classifications, rules, regulations, practices, or contracts to be thereafter observed and in force.

The foregoing order of the Commission is all inclusive, insofar as are concerned Gulf's rates for sales of natural gas in interstate commerce, subject to the Commission's jurisdiction. All of Gulf's such rates are being tested in its consolidated rate proceeding. There exists the legal presumption that these rates are there being tested by proper rate-making criteria and standards under the Act. Like all of Gulf's rates, the rate provided in its Rate Schedule No. 147, covering the aforesaid sale to United, is a challenged rate; and being "in line" with any such rate is no justification for holding that a rate is required by the public convenience and necessity.[10] This is very much the case in the light of the evidence presented by the Staff.

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[10] United Gas Improvement Co. v. F.P.C. (CA 9) 283 F. 2d 817; Public Service Commission of New York v. F.P.C. (CADC), 287 F. 2d 146; U.G.I. Co. v. F.P.C. (CA 5), 290 F. 2d 133.

Gulf was issued its aforesaid permanent certificate by order of the Commission of July 8, 1959, by which there were also issued 32 other certificates to various producers authorizing sales of natural gas in interstate commerce in Louisiana, Texas, Oklahoma, New Mexico, West Virginia and Pennsylvania. The Commission order was issued, according to statements therein, after a public hearing, held "pursuant to due notice", at which "no appearances other than staff counsel were entered upon the record and no evidence offered in opposition to the granting of the applications." The transcript of the hearing so held shows that no evidence was received in relation to Gulf's sale to United except "the application filed by Gulf Oil Corporation in Docket No. G–16745." There was no evidence in the record there which would provide any reasonable basis for a finding that Gulf's price of 18½ cents per Mcf, was, or was not, required by the public convenience and necessity. The proceeding was conducted in the manner of all ordinary uncontested cases before the Commission. Being "in line" with said Gulf rate gives no virtue to the price of 18.5 cents paid by United to the Applicants here. It cannot be said that there was given by the Commission in Docket No. G–16745, that "most careful scrutiny and responsible reaction to" Gulf's initial price proposal, which Catco said was required in such certificate proceedings.

Sales in South Louisiana

One brief of the Applicants states that "gas produced in Allen Parish, Louisiana, which, in all physical respects was comparable to the gas produced in Ada Field, is being sold at the initial base price of 18.5 cents per Mcf." To this is added, "These sales of gas in Allen Parish were negotiated in the same period as were sales of Ada Field gas, and all have been permanently certificated." An examination of the testimony cited at this point in the brief shows that there were four such sales in Allen Parish, each of which was "permanently and unconditionally certificated" by the Commission. Allen Parish is south of the "dividing line for the Northern and Southern Louisiana areas" fixed by the Commission on October 11, 1960, when it made public certain information concerning its General Policy Statement No. 61–1 of September 28, 1960; and sales from this area were not reflected in the Staff's exhibit which set forth the 77 sales in North Louisiana, hereinbefore discussed.

These four sales in Allen Parish were permanently certificated by the Commission at a base rate of 18.5 cents per Mcf. Each such sale was to United at United's "established" price. Each sale was certificated in an uncontested case, in which no real showing was made by record evidence that the certificate was, or was not, required by the public convenience and necessity. At the public hearing on the certificate application in each case, no appearances were made except by the Staff; and the only evidence received at each hearing in support of the application was the application itself. The proposed initial rates by the Applicants are "in line" with the Allen Parish rates in the same sense that they are "in line" with each other; and they were two cents higher than any other rate being paid by an interstate pipeline company in North Louisiana as heretofore shown. There is nothing about the permanent certification of the Allen Parish rates which gives weight to the contention of the Applicants that their proposed initial rates should be permanently certificated.

Sale to Texas Gas Transmission Company

The Applicants point to the sale by T. L. James and Co., Inc. (James), one of the Applicants here, to Texas Gas Transmission Company (Texas Gas) at an initial base price of 17 cents per Mcf, which has been permanently certificated by the Commission; and it is contended that the gas involved there was delivered at the tailgate of a processing plant in the Calhoun Field of

Ouachita Parish, and "it was determined by negotiations than an 18½-cent price from United would be necessary to meet the Texas Gas price of 17 cents." The sale by James to Texas Gas was permanently certificated in Docket No. G-19407 on July 14, 1960, in an order covering certificates issued in more than 100 dockets. There was no opposition to the issuance of the certificate in any one of this large number of dockets. No evidence was received in the uncontested hearing which had any probative force in relation to the issue of whether or not any of the numerous certificates were required by the public convenience and necessity. The contract between James and Texas Gas was not executed until July 22, 1959, about a year after United had "established" its price of 18.5 cents for gas purchased for its pipeline. The contract between James and United, at this established price was dated July 10, 1959. Attention is again called to the fact that there were 14 gas purchase contracts executed at 16.5 cents in North Louisiana in 1959. This permanently certificated rate of 17 cents per Mcf, in the sale by James to Texas Gas, certainly gives no validity to the contention of the Applicants that their rate of 18.5 cents is not "out of line."

The Sale by The California Company

The one other permanently certificated sale in North Louisiana selected as evidence by the Applicants was by The California Company (California) to Southern Natural Gas Company (Southern) by contract of October 10, 1958. The sale was of gas produced in the Lake St. John Field in Concordia and Tensas Parishes, which are on the Mississippi border, and the contract called for an initial contract base price of 21.5 cents per Mcf. The permanent certification of this sale was ordered on August 7, 1959, in Commission Opinion No. 325 in the proceeding entitled South Georgia Natural Gas Company, *et al.*, Docket Nos. G-9892 *et al.*, in which 12 dockets were consolidated for hearing. The California sale was covered by Docket No. G-16680. Concerning this sale the Commission had the following to say in its Opinion No. 325:

> As to the Lake St. John gas, the present authorization of this sale may be attended by unusual benefits. Southern does not plan on receiving deliveries of this gas until some six years hence, when the recycling operations are completed, although there is no question but that The California Company has firmly dedicated this gas to Southern. Under The California Company contract, the sale from both the Cranfield and the Lake St. John fields is a single sale and the price provisions of the contract apply to gas from either or both. However, if the Commission postpones issuance of a certificate for the Lake St. John field until deliveries from that field are about to commence, The California Company would have an immediate right to cancel the 1958 contract with respect to the Lake St. John field. Thus, certification of the Lake St. John sale now will determine at this time what will be the maximum price The California Company can charge for Lake St. John gas some six or seven years hence, a measure of consumer protection against the possibility of increased prices which is by no means insignificant.

There is no evidence in this record by which the sale by California to Southern can be held to be comparable to the sales here involved, which provide for prompt deliveries after Commission authorization and the construction of the necessary facilities to effect delivery. The situation in the California case in no way establishes that the sales here are not "out of line" with a great majority

of the prices contained in contracts executed for the sale of gas in North Louisiana during 1957, 1958, and 1959.

Nonjurisdictional Sales

The Joint Brief states that "numerous nonjurisdictional sales of significant quantities of gas are being made in the North Louisiana area", and cites pages of the transcript of the hearing at which appears testimony concerning such sales. Examination of this testimony shows that three sales of gas were made from production in Bossier and Webster Parishes, which are on the Arkansas border, to Reynolds Aluminum Company (Reynolds) for transportation and use in its plant in that State. The gas sold to Reynolds in Webster Parish was said to be only about 40 miles from the gas produced by the Applicants in the Ada Area of Bienville Parish. The prices under the three contracts with Reynolds ranged from about 18 cents to about 19.5 cents per Mcf at 15.025 psia, excluding tax allowance. These prices were claimed by one witness to be indicative of the "going price" in North Louisiana.

A price of 18.5 cents per Mcf, or 19.5 cents, cannot be classified as the "going price" when contracts for the sale of gas produced in the same general area are being regularly executed at 16.5 cents practically simultaneously. It has been pointed out hereinbefore that in 1958 there were 11 contracts executed in North Louisiana at 16.5 cents while United executed 10 at its "established" price of 18.5 cents. In 1959, while United was executing six contracts at 18.5 cents, there were 14 contracts executed in North Louisiana at 16.5 cents, and eight at 17 cents. The true "going price" was certainly no more than 16.5 cents per Mcf in North Louisiana in 1958, when United "established" its price of 18.5 cents, particularly when there was no evidence of any offer above 16.5 cents for the Applicants' gas by any other regulated pipeline company buying gas in the area. The "established" price of United no doubt was a factor in bringing about the price of 17 cents in the area for some of the sales executed in 1959. The Staff exhibit shows a good number of sales contracts executed in North Louisiana in 1957, 1958 and 1959, lower than 15 cents, some as low as 12 and 13 cents. In this period of time there were four contracts made for sales of gas at 12.5 cents per Mcf in Bossier Parish, where Reynolds contracted to pay 19.5 cents in 1958.

The Reynolds sales were all nonjurisdictional, in that the purchased gas, although transported across a State line, was not to be resold. Unregulated gas sales may not be held out as a measure for a proposed initial rate for a regulated sale. Of course, the contractual prices of unregulated sales may affect prices in the unregulated market place, but the market cannot lawfully ever be substituted for the regulation of rates under the Act. The sales to Reynolds may not be regarded as affecting the "line" beyond which no sale should be certificated. It has been held that "the only justification for giving the Commission the duty to regulate prices was the determination by Congress that the producers have a supply that is so restricted in relation to the demand that they have the economic power to bargain for prices that will be injurious to the public." [11]

Monsanto's Rates

Monsanto filed a separate initial brief, but joined in the Joint Reply Brief. Its initial brief referred to the Joint Brief with approval and then discussed its separate position. There appears in Monsanto's initial brief the following:

> The Commission's staff has conducted an investigation of Monsanto's costs as they related to all of Monsanto's rates and charges—*including the*

[11] United Gas Improvement Co. v. F.P.C. (CA 5), 290 F. 2d 133, 135.

instant rate to United. On the basis of this investigation, the Commission's staff concluded that Monsanto's rates, on a cost of service basis, and upon the basis of the staff's own costing methods and procedures, are not unreasonable and unjust. As a result the staff moved to dismiss the Commission's Section 5(a) investigation into all of Monsanto's rates and to vacate numerous suspensions, under Section 4(e), of Monsanto's rate change proposals. *Monsanto Chemical Company*, 22 FPC 1077 (December 18, 1959).

The motion to terminate was granted by the Examiner on November 18, 1959. This decision was affirmed by the Commission on December 18, 1959 (22 FPC 1077, 1078).

It is then related that a number of rate increases, then being collected by Monsanto subject to refund, were consolidated for hearing. It is claimed that at such hearing "Its presentation *on a cost of service basis, prepared in accordance with Commission precedents*, conclusively demonstrated that Monsanto's rates were just and reasonable (22 FPC 1078, 1079)", and that after such presentation a recess was taken, during which the Commission instituted an investigation of all of Monsanto's rates under Section 5(a) of the Act. The brief states that the Staff of the Commission then "made a field examination of Monsanto's books and records and as a consequence thereof moved to terminate the proceedings (22 FPC 1078, 1079)." After some discussion of the Staff's motion sustained by the Presiding Examiner and the Commission, the Monsanto brief asserts:

> In short, the Commission has investigated the 18½ cents per Mcf and has found that the rate was not unjust and unreasonable. Therefore, no possible basis exists for denying Monsanto's application or conditioning approval thereof on any revision of the 18½ cents per Mcf rate.

The proceedings so referred to by Monsanto, which involved its suspended rate increases, were in Docket Nos. G–9681, *et al.* The rate investigation, instituted by the Commission under Section 5(a) of the Act, was in Docket No. G–18318, which was consolidated with Docket No. G–9681 and the other dockets by order of the Commission of April 21, 1959. It is deemed advisable to set forth herein the pertinent parts of the Staff's motion to terminate such consolidated proceedings and the Presiding Examiner's decision thereon. Under that part of the motion entitled "Basis for Motion for Termination" it is stated:

> The Commission's staff has conducted an investigation of Monsanto's operations and has reviewed its expenditures and revenues shown on the company's books and records of its Lion Oil Company Division (Lion Oil). This investigation has followed the usual staff methods of analysis. One predominant factor emerged which contributed to an unusually high cost pattern overall. The staff's study revealed that the exploration and development program of Lion Oil greatly increased after its merger into Monsanto on September 30, 1955. Whereas before the merger Lion Oil had a ratio of exploration and development expenditures to revenues of 27% for the years 1953–55, as a division of Monsanto the comparable ratio has risen to over 50% for the 1956–58 period.
>
> The staff has, therefore, evaluated and given extended study and consideration to Monsanto's (Lion Oil Division) exploration and development program. It has concluded that whereas the company has launched into a greatly expanded leasing, seismographic, and drilling program, its production and sale of natural gas have not thus far increased sufficiently to provide increased revenues adequate to offset these increased costs. Furthermore, other costs, as allocated by Monsanto and recorded on the company books, appear to be questionable. However, because of the relatively large explora-

tion and development costs, the application of staff methods to such other costs would not appreciably affect final unit costs of gas. Under staff's costing methods, including tentative adjustments, the costs applicable to the sales under 31 out of 34 filed rate schedules were found to be substantially greater than the revenues derived from sales under those rate schedules in the test year 1957. In those three instances in which revenues exceeded costs only nominal amounts were involved.

In the next few years Monsanto may achieve a significant increase in revenues and a much lower expenditure ratio as a result of its expanded exploration program. In any event, it is clear to the staff that Monsanto's pattern of exploration operations has undergone a major change and has not been established sufficiently long to provide a basis for determining its rates and charges in these consolidated proceedings.

Consequently, in view of its investigation of Monsanto's records and operations, the staff takes the position that it will not present any evidence or otherwise proceed in these matters. However, it does not approve or adopt either Monsanto's presentation in favor of proposed increased rates in these proceedings or the prices contained in its filed rate schedules.

The basis for his order terminating the consolidated proceedings is given by the Presiding Examiner in his decision of November 18, 1959, as follows:

The first two formal findings of fact proposed by Staff Counsel and Monsanto are identical. Moreover, each of these parties agreed (with only differences as to language to be adopted) that the proceedings should be terminated. Monsanto asks however that additional findings be made to the effect that Monsanto has sustained its burden of proof to show that its rates are just and reasonable, and that the Staff's investigation of all said Monsanto rates admittedly provides no basis for a finding that such rates are unjust and unreasonable. Since there have been no hearings held since the consolidation with and addition of the investigative proceedings under Section 5(a) of the Act, we find it impossible to agree to the proposed finding as to burden of proof. Monsanto's other proposed additional finding is almost wholly in accord with the language of Staff Counsel's motion. We have reconciled the slight difference by adding a limitation of its application to the present time, and (with that addition) have adopted the said finding, as our own. We have also adopted Monsanto's language as to the final finding as being slightly more specific in application than that proposed by Staff Counsel.

* * * * * * *

Since the order herein does, in fact, give approval to the present and past use by Monsanto of the rates and charges contained in the suspended rate increase filings, as well as to the continuation for the present, at least, and until further Commission action, of the other rates included within the scope of the investigation heretofore initiated in Docket No. G–18318, we cannot adopt the portion of Staff Counsel's proposed Paragraph (C), which would withhold approval of these matters. We do feel however, that to the extent that matters of company accounting procedures or methods are involved, we should withhold approval here, since this is more or less a matter of decision by default, and the Staff of the Commission appear to have based their proposal to terminate these proceedings upon studies carried on and determinations reached by the use of the Commission Staff's own accounting procedures and methods rather than upon the basis of the accounting methods or procedures heretofore utilized by Monsanto either in the keeping of its permanent accounts or in the preparation of the testimony and exhibits

presented in this case. Moreover, no evidence was presented in regard to Docket No. G–18318 (the 5(a) investigation) as such, or in regard to the matters involved in the three rate increase proceedings (Docket Nos. G–14858, G–16807 and G–16808), added and consolidated by Commission order of April 21, 1959 and there is no record upon which affirmative findings of fact can be made as to these four parts of the consolidated proceedings.

The Presiding Examiner ordered that the hearing be concluded and the record closed, and his decision was adopted by the Commission on December 18, 1959. He made a specific finding that the proposed rate increases of Monsanto "should be permitted to continue in effect without being subject to refund." This was followed by another specific finding and an order reading, respectively, as follows:

(3) Staff's investigation of all of Monsanto's rates admittedly provides no basis for a finding that the rates of Monsanto are presently unjust and unreasonable.

* * * * * * *

(E) This order is without prejudice to any findings or orders which have been or may be made by this Commission in any proceeding now pending or hereafter instituted by or against Monsanto.

The only possible way the uncertificated initial rate of 18.5 cents, covering the sale by Monsanto to United here involved, could have been considered at all in the proceedings in Docket Nos. G–9681, *et al.*, was under the broad investigation instituted there by the Commission order of April 21, 1959. In the quotations above from the record there, it is shown that no evidence whatever was adduced in connection with the general investigation of all of Monsanto's rates under Section 5(a) of the Act. The only evidence in the record there was presented by Monsanto in its case-in-chief in support of its rate increases under Section 4(e) of the Act and all of this was adduced prior to the Commission order of April 21, 1959.

Under the peculiar circumstances recited in the Staff Motion as the basis for its request that said consolidated rate proceedings be terminated, there is nothing which persuades that it is required by the public convenience and necessity that a permanent certificate should issue in these proceedings, authorizing the initial rate of 18.5 cents, to Monsanto or any other Applicant here. In the face of the fact that said rate of 18.5 cents was two cents higher than most of the jurisdictional rates effected by contracts executed in 1957, 1958, and 1959, which indicates the reasonable probability of its unlawfulness under Section 4(a) of the Act, it cannot be found that the action of the Commission at Docket No. G–9681 shows that said rate is probably just and reasonable.

No Triggering

In their argument that their rate of 18.5 cents should be permanently certificated, the Applicants point to the fact that no rates are triggered by the contracts with United here involved. So far as the evidence in this record shows, no rate for gas being delivered under contract will be increased under the terms thereof merely by the payment of United's "established price" of 18.5 cents. However, this is not to say that the permanent certification of the initial prices here proposed by the Applicants would have no inflationary effect upon the price of natural gas in North Louisiana. This proposed initial price of 18.5 cents per Mcf is two cents higher than most of the contracts in this area executed in the period covered by the Staff exhibit. If this price is permanently certificated for

all the Applicants here, it would indeed be difficult for any interstate pipeline to purchase gas in North Louisiana for any less.

Production in North Louisiana

The Applicants presented evidence concerning the difficulties encountered in the exploration for new reserves by any producer in North Louisiana. These difficulties appear from the testimony to be general in this area and it is asserted in the Joint Brief that these "tend to increase the risk element of North Louisiana drilling to such an extent that the possible gain from investment in this area is not sufficient to offset the risk." Evidence was presented to show that exploration in North Louisiana is more difficult than that in South Louisiana where prices are higher. A somewhat dire picture is painted of the lot of the producer in North Louisiana, who Applicants contend, is confronted with peculiarly difficult situations in his exploration activities. No need is seen to set forth herein an enumeration of such difficulties, claimed by the Applicants to exist, as they would in no way point out where the "line" is, beyond which no rate should be permanently certificated in North Louisiana. Furthermore, there is nothing in the record to show that the North Louisiana producer who was contracting in 1958 and 1959 to sell his gas at 16.5 cents and considerably less, had not been confronted with the same difficulties of exploration and production as had been the Applicants here.

The contention is made by the Applicants that, because of these production difficulties, a steady decline has occurred in North Louisiana exploration and production, and that "a greater incentive to encourage exploration" for "new gas reserves" is there required. "Greater" than what must this "incentive" be? The Applicants claim that increased exploration and production activity has resulted in North Louisiana since United "established" its rate of 18.5 cents in 1958. It is elementary in economics that the higher the price of a product, the greater will be the incentive to produce it. It is also elementary in this field of regulation that the greater the authorized initial rate for the sale of natural gas in interstate commerce, the greater may be the exploitation of the consuming public. This "incentive" of 18.5 cents for North Louisiana is found to be beyond the "line" to be held while it is being tested by rate-making standards under Sections 4 and 5 of the Act.

The Increment of Incentive

The Fifth Circuit Court of Appeals remanded to the Commission the El Paso rate case [12], and its opinion concluded with this statement:

> Upon such remand the Commission will receive such evidence as may be necessary to enable it to fix a just and reasonable rate to permit a fair return on the well-mouth investment and provide the incentive necessary to attract capital to the exploration and development activites of the company.

It is beyond question that a producer of oil and natural gas should be allowed this incentive to explore. It must be made commensurate with the risks he takes, while balancing his interests with those of the consumer. However, this incentive must be measured by some rate-making standards so that it will not exceed what is needed as such.[13] This is not accomplished by accepting the price arrived at by such negotiations in the open market where the producer, being human, will endeavor to obtain "all the traffic will bear" for his natural gas, the supply of which "is so restricted in relation to demand" [14] that he has

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[12] El Paso Natural Gas Co., *et al.* v. F.P.C., 281 F. 2d, 567, Cert. denied 366 U.S. 912.

[13] City of Detroit v. F.P.C., 230 F. 2d, 810; Cert. denied Oct. 8, 1956. Forest Oil Corp. v. F.P.C., 263 F. 2d, 622.

[14] See footnote 11.

an enormous advantage in the market. Furthermore, the Act calls for the regulation of rates by the Commission, which has authority to impose, under Section 5(a) of the Act, the "lowest reasonable rates"; and such regulation is not brought about by permitting the market to control prices.[15]

Hereinafter an order is made which will give the Applicants the opportunity to have their proposed initial rate of 18.5 cents measured in a way to balance their interests with those of the consuming public. As regulated natural gas companies, they have the right to have this measure of their contractual price made in a subsequent proceeding under Sections 4 and 5 of the Act. It is only in such a proceeding that a proper determination can be made of whether the rate of 18.5 cents is no more than is reasonably necessary to effect "a fair return on the well-mouth investment and provide the incentive necessary to attract capital to the exploration and development activities" of the Applicants. The primary aim here is to respect and carry out the mandate of Catco and "hold the line" while such determination is being made. The "line" would not be held if a rate is certificated here which is two cents higher than most of the rates contracted in 1958 and 1959 by other pipeline companies to be paid for natural gas produced in North Louisiana.

The Southern-Grigsby Controversy

Southern intervened in these proceedings to oppose only the application of Grigsby in Docket No. G–19705. Grigsby is the only Applicant here selling gas to United from what is known as the Bear Creek Field in Bienville Parish. Southern claims to own "a substantial portion of the reserves" in this field, by reason of gas purchases and its own production there. Southern contends that to certificate Grigsby's proposed initial rate of 18.5 cents, "would increase the prevailing market price in the field", and that this would in turn, "increase the amounts Southern must pay its royalty owners and would result in increased costs" to its consumers.

Southern argues that if the prevailing market price is increased in Bear Creek Field, it must pay these increased royalties to its royalty owners under Louisiana law; and it gives in its brief citations to Louisiana and Federal Court decisions claimed to support this argument. Southern has presented evidence to show the extent of its increased royalty payments if the market price should be so increased. Grigsby's reply brief challenges Southern's position. If the public convenience and necessity required the certification of rates higher than the prevailing market price, an incidental increase in royalty payments would just have to be paid.

Southern also contends that Grigsby's proposed initial rate is "out of line" with prices being currently paid for gas produced in the Bear Creek Field. An examination of the Staff's exhibit shows that this sale by Grigsby to United was the only jurisdictional sale from this field for which a contract was executed in the 3-year period from 1957 to 1959, inclusive. It is believed that it would be fairer to judge Grigsby's price in relation to the prices in North Louisiana as a whole rather than in relation to prices in a single field in that area. Bear Creek Field is in Bienville Parish as is the Ada Field, where 9 of the 16 sellers to United produce their gas. Southern presented evidence to show its going price and that of two other interstate pipeline companies paid in the Bear Creek Field, but it may be assumed that these going prices were contracted for prior to 1957, as the Staff exhibit shows only the Grigsby sale from this field during the three years covered by it. Southern's brief does not "propose any specific

[15] City of Detroit v. F.P.C., 230 F. 2d, 810; and Bel Oil Corporation v. F.P.C., 255 F. 2d, 548.

level at which a price condition should be imposed in Grigsby's certificate," stating that the fixing of such level "is a function of the Examiner and the Commission in the exercise of that responsible reaction required by Catco."

TEMPORARY AUTHORIZATIONS

When an application is filed for a certificate of public convenience and necessity authorizing the sale of natural gas in interstate commerce by an independent producer, Section 7(c) of the Act requires that "the Commission shall set the matter for hearing and shall give such reasonable notice of the hearing thereon to all interested persons as in its judgment may be necessary under rules and regulations to be prescribed by the Commission." This is a most important requirement, if the primary aim of the Act is to be accomplished. Those who will pay for the gas, which is the subject of the sale, and who are not parties to the gas purchase contract, are entitled to this notice in order that they may have opportunity to defend against the payment by them of an initial rate which may be excessive, and to oppose the approval by the Commission of any other provision of the contract which may be detrimental to their interests. These payers of the gas bills are indeed comparable to a defendant or a respondent against whom a money judgment is sought, and no such judgment would be valid without notice to such defendant or respondent who is within the territorial jurisdiction of the Court.

The Congress carefully provided in Section 7(c) that such reasonable notice of the application to all interested parties should not be denied except "in cases of emergency" due to the existence of which "the Commission may issue a temporary certificate * * * to assure maintenance of adequate service or to serve particular customers." This is an emergency power of the Commission which is validly exercised by it only after a finding by it, based upon substantial proof presented, that there exists an emergency such as would justify in the sense of the statutory language, the issuance of a temporary certificate without notice to all interested parties.[16] The fact that the certificate is only to be temporary "pending the determination" of the application for a permanent certificate does not in any way lessen the statutory requirement that what is authorized by the temporary certificate must be required by the public convenience and necessity. If the temporary certificate is to authorize a sale of natural gas by an independent producer, all of the terms and conditions of the temporarily authorized sale must indeed be required by the public convenience and necessity. While the proposed initial rate is not required to be measured by intricate rate-making standards before it may be temporarily authorized, the Catco rule for holding the line is just as applicable to the issuance of a temporary certificate as to the issuance of a permanent certificate. There is no conceivable emergency, in the sense of the Act, which would justify ignoring this Catco rule in the issuance of a temporary certificate authorizing a sale of natural gas by an independent producer. This is particularly true because the payers of the gas bills are not being given opportunity to defend against the payment by them of what may be an excessive initial rate.

The emergency power of the Commission to issue temporary certificates is discussed in the Algonquin case. The question there was whether certain authorization sought by Algonquin "would be within the Commission's statutory authority to 'issue a temporary certificate in cases of emergency, to assure maintenance of adequate service or to serve particular customers without notice

[16] Algonquin Gas Transmission Co. v. F.P.C., 208 F. 2d, 334. (Algonquin).

or hearing, pending the determination of an application for a [permanent] certificate' ". Concerning this question, the Court stated that the "crucial phrases are 'to assure maintenance of adequate service' and 'to serve particular customers' ". Following this last quoted statement in the opinion is a reference to a footnote in which the Court asserted: "It is for the Commission to find as a matter of fact whether the requisite emergency exists." This is elementary in the law. If an agency of Government is given authority to do certain things in the presence of an emergency, the "requisite emergency" must be shown by a specific finding of the agency to exist before the agency may exercise such emergency authority. The finding that the emergency exists is necessary to create the power to act summarily and without public hearing and due notice thereof to all interested parties, when emergency authorization is sought under the Act. It is just not lawful to issue temporary authorizations of jurisdictional sales of gas as a routine matter without the required consideration being given, first, to whether an emergency exists which requires summary action and, second, what summary action is required by the public convenience and necessity, particularly in the sense of Catco line holding.

Eight of the fourteen Applicants here were issued temporary authorizations to sell natural gas at the full contract price of 18.5 cents per Mcf, without any provision whatever for refunding any part of such price which might ultimately be found not justified by the Commission. An examination of the formal files in all of said dockets, discluses that no action whatever by the Commission was taken in relation to any of the eight temporary authorizations. So far as is disclosed by these formal files, there was no finding made in any case that an emergency existed which made the temporary authorization of the sale necessary or even justified. There is no finding made in any of these dockets that the public convenience and necessity required the issuance of temporary certificates authorizing sales to be made by these eight Applicants at 18.5 cents per Mcf. Pan American, one of the eight Applicants holding such temporary authorizations, is no longer selling to United because its gas has been depleted, as hereinbefore shown. The other seven such Applicants have all been collecting for about three years 18.5 cents per Mcf from United for their gas, and there is apparently no way to obtain a refund of such part of this initial rate as exceeds the initial rate found herein to be required by the public convenience and necessity.

By Order No. 193, issued November 20, 1956, the Commission promulgated what is now Section 157.28 of its "Regulations under the Natural Gas Act," which is entitled "Temporary authorizations." Sections 157.23 to 157.27 were previously in effect and covered applications for certificates of public convenience and necessity by independent producers, without provision for temporary authorizations. In reading Section 157.28 it must be kept in mind that a "temporary certificate" may only be issued by the Commission itself in the exercise of its emergency power given in Section 7(c) of the Act. And yet, Section 157.28 makes it possible for an independent producer to "initiate the sale" of gas which "may proceed forthwith," upon the Secretary's "acceptance of the rate filing and the statements made under this section." The "statements made under this Section" refer to the requirements of the Section for the contents of the application filed for a certificate authorizing the particular sale. Such requirements as are pertinent here are set forth in paragraph (c) of Section 157.28 as follows:

> (c) As part of its application hereunder, or separately, the applicant independent producer must file or have on file (1) a statement of intention to invoke this section, setting forth the facts constituting the emergency requiring such action, which emergency may include, *inter alia*, drainage,

threatened loss of lease, flaring, economic hardship resulting from payment of shut-in royalties, or similar situations; and (2) a statement identifying the contract tendered as the rate schedule intended to be effective for the sale or transportation under this temporary authorization.

There was used to indicate the Secretary's "acceptance of the rate filing and statements made under this Section," a printed form which was designated as "F.P.C. Form No. 443 (Rev.)." The first two paragraphs of this form, which is addressed to the applicant, and signed by the Secretary, read as follows:

> Your statement, filed pursuant to Section 157.28(c)(1) of the Commission's Regulations, of your intention to invoke said Section and initiate the service proposed in the amendment to the certificate application, Docket No. G– is hereby accepted.
>
> You are also advised that the related rate schedule, identified by your statement pursuant to Section 157.28(c)(2) of the Regulations and listed at the bottom of this letter, has been accepted for filing to be effective on the date of initial delivery. Please advise this Commission of the date of initial delivery of gas thereunder. This acceptance of the rate schedule for temporary service is no assurance that it will be accepted by the Commission for permanent service.

While the form states that the "acceptance of the rate schedule for temporary service is no assurance that it will be accepted by the Commission for permanent service," it nevertheless authorizes the collection of the contractual initial price "pending the determination" of the application for the permanent certificate without any protection for the consumer against exploitation by the collection of a temporary rate which may exceed the initial rate found to be required by the public convenience and necessity when such "determination" is made. The form, which is for the signature of the Secretary, concludes with the following paragraph:

> This constitutes all requisite temporary authorization to commence the sale of gas, but such authorization and acceptance of the rate schedule are without prejudice to such final disposition of the certificate application, as amended, as the record may require and, furthermore, once service is commenced under this authorization it may not be discontinued without permission of the Commission issued pursuant to the provisions of the Natural Gas Act.

Temporary authorizations with no rate condition were issued to Ohio, Southwest (G–15460), Nowerys, Kinsey, Hunt Company, Hunt Trust, Pan American and Monsanto, between July 14, 1958 and January 29, 1959. Six of such temporary authorizations were upon the printed form described above and were signed by the Secretary. The temporary authorization issued to Kinsey was essentially the same as said form except that it contained the condition that this Applicant would make refund of a certain part of the Louisiana tax if the law imposing the tax were held to be invalid. The temporary authorization issued to Monsanto was, like all the eight authorizations here discussed, issued by the Secretary pursuant to Section 157.28 of the Regulations; but it was not upon said form and it contained no rate condition. In these eight dockets temporary authorizations have been issued routinely without a finding by the Commission that an emergency existed requiring this summary action and, without, so far as the record shows, any consideration being given to the question of whether the temporarily authorized sales, in all of their terms including price, were required by the public convenience and necessity. In none of the eight temporary authorizations issued by the Secretary to the Applicants named above, was there any indication that the issuance thereof was "by direction of the Commission," as was

indicated in later authorizations issued by the Secretary to the other six Applicants. It is true that each application averred the existence of one of the types of emergency enumerated in Section 157.28(c) of the Regulations, but such averment of an emergency does not constitute the requisite finding by the Commission that an emergency exists. Furthermore an "acceptance" by the Secretary cannot lawfully be substituted for Commission action upon a request of it for the exercise of its emergency power.

When a temporary authorization was issued to the Applicant Robinson on March 16, 1959, it was indicated above the signature of the Secretary thereon that it was issued "by direction of the Commission," and a rubber stamp thereon shows that it was "approved by the Commission" on March 16, 1959. It was stated in the first paragraph of this authorization that it was "conditioned on L. L. Robinson, *et al.*, refunding to United any amounts in excess of the amount resulting from the rate finally determined to be proper in Docket No. G–16457." When a temporary authorization was issued to Atlantic on July 8, 1959, it was certified therein, over the signature of the Secretary, that it was issued "by direction of the Commission," and had been "approved by the Commission." This contained the same condition as that imposed in the Robinson authorization, namely, that Atlantic would refund to United "any amounts in excess of the amount resulting from the rate finally determined to be proper in Docket No. G–18572." It is ordered hereinafter that the Applicants Robinson and Atlantic make refunds in accordance with the rate condition imposed in their temporary authorizations.

The original application in Docket No. G–19112 was filed by Southwest on July 27, 1959. On September 9, 1959, a temporary authorization was issued to Southwest, which was signed by the Secretary and it showed that it was "by direction of the Commission." A notation shows that it was approved by the Commission. This temporary authorization contained a condition that the initial rate "shall not exceed 17 cents per Mcf at 15.025 psia, plus applicable tax reimbursement." A letter from Southwest to the Secretary of September 11, 1959, requested reconsideration of its application and the issuance of a temporary authorization without rate condition. This request was denied by the Secretary on November 25, 1959. The temporary authorization of September 9, 1959 was finally accepted by Southwest by letter of March 4, 1960. On June 10, 1960, the temporary authorization was amended in certain respects based upon the request in the supplemental application filed by Southwest on April 25, 1960, but the amendment did not change the rate condition. There were two subsequent supplemental applications filed, upon the basis of which temporary authorizations were issued. Each such contained a rate condition that the price to United "shall not exceed 18.75 cents per Mcf including any tax reimbursement," which made the base rate remain at 17 cents per Mcf.

A temporary authorization was issued to James on October 23, 1959, upon the condition that the price to be paid by United "shall not exceed 17 cents per Mcf at 15.025 psia plus applicable tax reimbursement." This authorization was not accepted by James within the 10 days given for this purpose. On March 9, 1960, James requested that the time for such acceptance be extended, and this request was granted by the Commission on April 1, 1960, which made effective the acceptance of the temporary authorization transmitted by James with its letter of March 9, 1960. There was filed with the Commission on October 10, 1960, a supplemental application by James for authority to dedicate additional acreage to United, to be covered by its existing sales contract. A second temporary authorization was issued to James on December 1, 1960, upon the condition that the price to be paid by United "shall not exceed 18.75 cents per Mcf at 15.025 psia

including tax reimbursement." This condition required that base rate not exceed 17 cents, the tax being 1.75 cents. This second authorization was accepted by the letter from James of December 7, 1960. A second supplemental application was filed by James in the same docket, covering additional acreage in the Calhoun Field, on February 23, 1961, and a third temporary authorization was issued to James in this docket on March 30, 1961, which was accepted by its letter of April 6, 1961. This authorization contained the same rate condition as that imposed in the authorization of December 1, 1960. All three of the temporary authorization issued to James were shown to be "by direction of the Commission."

Grigsby filed his original application on October 12, 1959. On November 6, 1959, the Secretary issued to Grigsby, by direction of the Commission, a temporary authorization containing the condition that the price to United "shall not exceed 17 cents per Mcf at 15.025 psia plus applicable tax reimbursement." This authorization was accepted by Grigsby by letter of November 13, 1959. A second temporary authorization, based upon an amendment to the original application, was issued to Grigsby on November 3, 1960, and was amended by the Secretary on March 1, 1960. It contained the same rate condition as that in the original authorization.

Upon the basis of an original and supplemental application, there was issued to Roberts on January 14, 1960, a temporary authorization which contained the condition that the price to be paid by United "shall not exceed 17 cents per Mcf at 15.025 psia plus applicable tax reimbursement." The acceptance of this authorization by Roberts was dated January 18, 1960.

It has been shown above that there were 8 of the 14 Applicants in these consolidated proceedings who were issued temporary authorizations by the Secretary, pursuant to Rule 157.28, without rate condition; and with the exception of Pan American, these Applicants have been collecting from United for about three years the base rate of 18.5 cents per Mcf. Two Applicants, Robinson and Atlantic, have accepted temporary authorizations containing the condition that they make refunds to United of "any amounts in excess of the amount resulting from the rate finally determined" in their respective certificate applications here consolidated. Four Applicants, Southwest (G–19112), James, Grigsby and Roberts, accepted temporary authorizations conditioned to require the payment of a base rate of only 17 cents per Mcf. For reasons hereinbefore stated, refunds may only be ordered to be paid by Robinson and Atlantic.

In no single docket of the 14 here consolidated is there a finding by the Commission that an emergency existed which made necessary or even advisable that a temporary authorization be issued for a sale of natural gas without notice to the ultimate payers of the sale price. Furthermore, there was no finding in any of these dockets, so far as the formal files show, that the issuance of the temporary authorization was required by the public convenience and necessity. Section 7 of the Act contemplates the issuance of no other kind of certificate than one that "is or will be required by the present or future public convenience and necessity," be it temporary or permanent.

Rate Condition

All of the Applicants, of course, contend that the certificates sought by them should be issued without condition so as to authorize their sales of gas at the contractual base price of 18.5 cents per Mcf plus tax reimbursement. United likewise so contends. The Applicants have failed to sustain their burden of proof to show that the public convenience and necessity require the issuance of certificates to them as applied for. The record evidence indicates clearly that

the initial rate should be fixed at less than the contractual initial price in each certificate issued to the Applicants.

Philadelphia urges in its brief that "the Grigsby sales from reservoirs common to wells of Southern Natural Gas Company should be continued at 10.35 cents per Mcf and all other Grigsby sales and sales by other Applicants should be continued at the Commission ceiling for 'old' gas (14 cents per Mcf plus tax)." The second figure refers to the rate of 14 cents per Mcf at 15.025 psia fixed for "increased rates" for North Louisiana in Appendix A to Statement of General Policy No. 61–1. (No. 61–1) This specific request of Philadelphia is denied, and the rates for Grigsby and all Applicants are set at a higher amount than 14 cents for reasons shown herein.

The brief of Staff Counsel asserts that although the evidence presented by it "shows the preponderance of permanently certificated sales in the North Louisiana area have initial prices at 16.5 cents per Mcf (exclusive of tax reimbursement), it is noted the initial price level established by the Commission in its Statement of General Policy No. 61–1, issued September 28, 1960, as amended, is 17.0 cents per Mcf" at 15.025 psia exclusive of tax reimbursement. The brief then states, that in view of the aforesaid price fixed by the Commission, "it is the recommendation of the Staff that the issuance of certificates in these proceedings be subject to condition that the base initial price shall not exceed 17.0 cents per Mcf at 15.025 psia for pipeline quality gas and that the total initial price for such gas, including partial reimbursement for present taxes, as provided for in the contracts, shall not exceed 18.75 cents per Mcf." No. 61–1 speaks of Appendix A thereto as containing "maximum acceptable rates," and it is said that in ordinary circumstances "proposed initial sales of natural gas by independent producers which include rates higher than those indicated in the appendix attached to this statement shall be denied a certificate or certificated only upon the condition that lower rates be filed." No. 61–1 is not construed to mean that, in proceedings under Section 7 of the Act for the certification of a sale, the initial rate may not be made lower than the "initial service rates" there specified for an area, if the public convenience and necessity require a lower rate upon the basis of the evidence.

The evidence in the record has been discussed extensively herein. Based upon all of the record evidence, it is found that the public convenience and necessity require that there be attached to each certificate issued in these consolidated proceedings the condition that each Applicant shall file a rate schedule with the Commission providing for a rate not exceeding 16.5 cents per Mcf at 15.025 psia plus appropriate tax reimbursement, for gas sold to United under the gas purchase contracts here involved. The evidence in this record very definitely would not justify the permanent certification of an initial base rate in excess of 16.5 cents per Mcf, while taking into consideration the CATCO mandate "to hold the line awaiting adjudication of a just and reasonable rate."

It is here reiterated that the attachment of this rate condition to the certificates here issued is not a holding that the contractural initial base price of 18.5 cents is unjust and unreasonable. The holding is that the sales here involved at this base price of 18.5 cents per Mcf are not required by the public convenience and necessity in these proceedings under Section 7 of the Act. The initial base rate of 16.5 cents per Mcf plus tax here certificated is the rate authorized to be charged by the Applicants "awaiting adjudication" of whether the contractural initial base price of 18.5 cents per Mcf is just and reasonable in the sense of Section 4(a) of the Act. Opportunity is herein given to all Applicants to bring about the prompt institution of a rate proceeding in which such adjudication may be made.

The condition hereinafter attached to the acceptance of the certificates here issued and to the compliance therewith by the filing of rate schedules calling for the initial base rate of 16.5 cents per Mcf, plus appropriate tax reimbursement, is that each Applicant will thereafter have the right to file, under Section 4(d) of the Act, a rate schedule calling for an increased rate of 18.5 cents per Mcf, plus appropriate tax reimbursement, 30 days prior to the proposed effective date thereof, and upon the expiration of such period of notice, the operation of such newly filed rate schedule will be suspended for only one day and the new rate may then, upon motion of such Applicant, become effective subject to refund, with bond given. The consuming public will then be protected against loss from the payment of such part of the base rate of 18.5 cents as may ultimately be found not justified by the Commission, according to rate-making standards.

All findings of fact or conclusions of law requested by any party to these proceedings, which have not been made hereinbefore either specifically or in substance, are hereby denied.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal, or upon its own motion as provided in the Commission's Rules of Practice and Procedure, that:

(A) Certificates of public convenience and necessity be, and they are hereby, issued respectively to all of the Applicants whose names are set forth in the caption hereof, with the exception of Pan American Petroleum Corporation, Docket No. G–17028, authorizing the sale by them of natural gas to United Gas Pipe Line Company for resale in interstate commerce, as set forth in their respective applications in the docket numbers set opposite their names respectively in the caption hereof, and as shown in the record of these proceedings, and further authorizing the construction and operation of any facilities used by them in making such sales which are subject to the jurisdiction of the Commission, upon the terms and conditions of this order.

(B) The certificates issued in Paragraph (A) hereof are granted upon the express condition and requirement that each of the Applicants referred to in Paragraph (A) shall file a rate schedule with the Commission within 30 days from the issuance of this order, providing for a rate not exceeding 16.5 cents per Mcf at 15.025 psia plus appropriate tax reimbursement for natural gas sold and delivered to United Gas Pipe Line Company, pursuant to the contracts here involved; and no sale to this pipeline purchaser shall be lawful after 30 days from the issuance of this order, which is not made pursuant to such rate schedule filed as hereby required.

(C) The acceptance of these certificates issued to the specified Applicants in Paragraph (A) hereof, as conditioned in Paragraph (B) hereof, and the compliance therewith, are upon condition that the Applicants receiving the certificates so conditioned, shall have the right thereafter to file under Section 4(d) of the Act, a rate schedule calling for the rate of 18.5 cents per Mcf at 15.025 psia plus appropriate tax reimbursement, 30 days prior to the proposed effective date thereof; and upon the further condition that, if such filing is made, the operation of such rate schedule will be suspended for a period of one day following the expiration of such 30-day period of notice, and thereafter, upon motion of the filer of such rate schedule, the rate provided therein may become effective subject to refund with interest at 7 percent per annum, under proper bond given as required by Commission order, of any portion of such increased rate which is ultimately found not justified by the Commission, under rate-making standards.

(D) The Applicants L. L. Robinson *et al.*, Docket No. G–16457 and The Atlantic Refining Company, Docket No. G–18572, shall, within 60 days of the time when this decision becomes the official action of the Commission, refund to United, with interest at 6 percent per annum from the date of payment by United to the date of refund, the excess of the total amounts charged and collected for all sales to United at the base rate of 18.5 cents per Mcf, made under the contracts here involved, over the total amounts which would have been charged at the base rate of 16.5 cents per Mcf, which initial base rate is found herein to be required by the public convenience and necessity. All expense incident to making these refunds will be borne respectively by these Applicants.

DANIEL J. KELLY,
Presiding Examiner.

APPENDIX A

Name of Applicant	Docket No.	Date of contract	Commission authorization	Authorized base price
The Ohio Oil Company, Operator, et al.	G–15385	June 10, 1958	July 14, 1958	18.5
Southwest	G–15460	July 3, 1958	Aug. 21, 1958	18.5
Southwest	G–19112	July 10, 1959	Sept. 9, 1959	17.0
Nowery	G–16190	July 24, 1958	Sept. 23, 1958	18.5
Kinsey	G–16278	Aug. 15, 1958	Sept. 29, 1958	18.5
Robinson	G–16457	July 23, 1958	Mar. 16, 1959	18.5
Hunt Company	G–16737	Sept. 23, 1958	Oct. 31, 1958	18.5
Hunt Trust	G–16763	Sept. 30, 1958	Nov. 5, 1958	18.5
Monsanto	G–17519	Oct. 27, 1958	Jan. 29, 1959	18.5
The Atlantic	G–18572	Feb. 20, 1959	July 8, 1959	18.5
James	G–19408	July 10, 1959	Oct. 23, 1959	17.0
Grigsby	G–19705	Oct. 8, 1959	Nov. 6, 1959	17.0
Roberts	G–19810	Oct. 14, 1959	Jan. 14, 1960	17.0

SOUTHWEST GAS CORPORATION, DOCKET NO. CP62–110

ORDER ADOPTING DECISION OF PRESIDING EXAMINER

(Issued March 21, 1962)

*Syllabus**

1. Merger found in the public interest since (1) evidence shows there is not now and has never been competition between the two companies; (2) Combined system would be considerably strengthened financially and thus enabled to more readily secure financing for needed expansion; (3) opportunities for improvement in load factor would increase; and (4) cost savings would be realized, which under Commission regulation, should ultimately be reflected in lower rates. P. 590.
2. Commission *issues* certificate of public convenience and necessity under Section 7 of the Natural Gas Act, authorizing merger. P. 592.

Ezekiel G. Stoddard and *Charles H. McCrea* for Southwest Gas Corporation.

David S. Lichtenstein for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

The decision of the Presiding Examiner in the above-captioned proceeding was issued on February 19, 1962. No exceptions have been filed to the decision. The Commission has considered the entire record before the Presiding Examiner.

*Initial decision appears on page 584.

The Commission finds:

In view of the foregoing, and after due consideration, the aforesaid decision should be adopted as the opinion of the Commission, with a more specific reference, however, in the ordering part of the Examiner's decision to the vesting in Southwest Gas Corporation (Southwest) of the certificates of public convenience and necessity heretofore issued to Nevada Natural Gas Pipe Line Company (Nevada).

The Commission orders:

(A) The decision of the Presiding Examiner in Southwest Gas Corporation, Docket No. CP62-110 issued on February 19, 1962, be adopted as the Opinion of the Commission.

(B) The Decision referred to in (A) above be effective as the Opinion of the Commission as of the date of issuance of this order.

(C) Southwest is hereby vested, as provided in paragraph (B) of the order of the Presiding Examiner, with all rights, and charged with all obligations and responsibilities of Nevada under the following rescinded certificates of public convenience and necessity:

	Docket Nos.	
1	G-1888	Order issued June 23, 1952, as amended March 9, 1953, November 13, 1953, and May 20, 1954.
2	G-8997	Order issued November 25, 1955, as amended January 2, 1958.
3	G-9436	Order issued June 8, 1956.
4	G-10522	Order issued December 27, 1956.

DECISION

UPON APPLICATION PURSUANT TO SECTION 7(C) OF THE NATURAL GAS ACT

(Issued February 19, 1962)

MARSH, *Presiding Examiner:* This proceeding is upon the application filed by Southwest Gas Corporation (Southwest) on October 30, 1961, and supplements thereto filed on November 3, November 14, November 21, and December 6, 1961, respectively, pursuant to the provisions of Section 7 of the Natural Gas Act for a certificate of public convenience and necessity authorizing Applicant to acquire by statutory merger and to operate all of the facilities of Nevada Natural Gas Pipe Line Company (Nevada).

Pursuant to the notice of application and date of hearing issued by the Secretary of the Commission on December 29, 1961, the matter came on for hearing, and was heard, on January 25, 1962, with the undersigned presiding. The matter had originally been set down as a noncontested hearing pursuant to Section 1.30 of the Commission's Rules of Practice and Procedure. Although the Secretary's notice of December 29, 1961, made provision therefor, no protests or petitions to intervene have been filed herein. On January 12, 1962, the Commission issued an order defining the issues herein to assure that the policies and provisions of the anti-trust laws be taken into account.

At the conclusion of the presentation of evidence, counsel for the Applicant moved for the waiver of the intermediate decision procedure which such motion was immediately transmitted to the Commission for its consideration and disposition. On February 12, 1962, the Commission issued an order denying the motion. Briefs have been filed and the matter is now ready for decision.

Southwest Gas Corporation is a corporation duly organized and existing under the laws of the State of California and is authorized to transact business in the

States of Arizona, California and Nevada. The principal office of the Applicant is located in Las Vegas, Nevada. Southwest is a public utility engaged in the distribution of natural gas at retail in Las Vegas, Nevada and its environs, the districts of Barstow and Victorville in California and the districts of Coolidge, Casa Grande and Clifton-Morency in Arizona. It operates under certificates of public convenience and necessity issued by the Arizona Corporation Commission, the California Public Utilities Commission and the Nevada Public Service Commission, respectively. Southwest provides public utility natural gas service to approximately 40,000 customers divided almost equally between the three states above named. Applicant has not heretofore engaged in the transportation in interstate commerce for the sale in interstate commerce for resale of natural gas. Southwest makes no city gate sales to distributors and no sales of natural gas for resale. Applicant purchases all gas for resale to its customers in Arizona from El Paso Natural Gas Company, all gas for resale to its customers in California from Pacific Gas and Electric Company and all gas for resale to its customers in Nevada from Nevada Natural Gas Pipe Line Company. Southwest, with respect to the transportation, distribution and sale of natural gas in the State of California, has been declared exempt from the provisions of the Natural Gas Act. (*Southwest Gas Corporation*, Docket No. G–9693, 15 FPC 1104).

For the period October 1, 1960, through September 30, 1961, Southwest's sales totaled 10,683,365 Mcf of which 2,756,776 Mcf were sold through Applicant's distribution systems serving Nevada, 1,942,657 Mcf through its distribution systems in California and 5,983,932 Mcf through its distribution systems in Arizona. As of August 31, 1961, Southwest's total assets amounted to $15,660,159. Its total operating revenues for the 12 months ended August 31, 1961, were $8,401,230.

Nevada Natural Gas Pipe Line Company is a corporation duly organized and existing under the laws of the State of Nevada, having its principal office in Las Vegas, Nevada. Nevada owns and operates approximately 223 miles of main transmission lines, 32½ miles of sales laterals, and other appurtenant facilities. Included among its facilities are two parallel transmission lines extending about 114 miles from a connection with El Paso Natural Gas Company near the Arizona-Nevada State line, in a northerly direction through a portion of California to the Las Vegas, Nevada area where it sells gas to Southwest for resale in that community and to California-Pacific Utilities Company for resale in Henderson, Nevada and to Boulder City, Nevada for resale therein.

El Paso delivers natural gas to Nevada at two delivery points, one on the California-Arizona State line and one on the Nevada-Arizona State line. Nevada transports this gas through its two pipelines to Southwest's franchise area in and around Las Vegas. The pipeline facilities owned by Nevada in the State of Arizona are leased to El Paso, and Southwest has been certificated by the Arizona Corporation Commission to provide the purely local distribution service from taps on this main line in the State of Arizona.

Nevada is principally engaged in the transportation and sale of natural gas to certain public utility and industrial customers in the vicinity of Las Vegas, Nevada. It has no production of natural gas and obtains all of its supply of gas from El Paso Natural Gas Company.

For the 12 months ended November 30, 1961, Nevada's total sales were 15,302,515 Mcf. Of this total, 3,109,738 Mcf were sales to natural gas utilities, 4,831,472 Mcf were firm industrial sales and 7,361,305 Mcf were interruptible sales to Nevada Power Company.

As of August 31, 1961, Nevada had total assets of $8,485,631 and for the 12 months ended August 31, 1961, its total operating revenues were $6,645,165.

The record shows that Nevada owns all the outstanding stock of the Utility Financial Corporation and the Carson Water Company.

Nevada is a natural gas company within the meaning of the Natural Gas Act and operates under certificates of public convenience and necessity granted by the Commission in an order dated June 19, 1952, in Docket No. G–1888 and Opinion and Order No. 289 dated November 25, 1955, in Docket No. G–8997.

The physical facilities of the two companies are "end to end." Southwest and Nevada perform entirely different functions, one that of distribution, the other that of transmission. Consequently, there is no competition between them. Nevada makes no sales in California or Arizona. In Nevada its sales to direct industrial customers are outside the certificated area served by Southwest and its sales for resale to the other two utilities, namely, California-Pacific and Boulder Natural Gas Company are at points outside Southwest's certificated area. As has been pointed out, Southwest and Nevada do not provide the same type of service. Nevada is a transmission company and has neither the personnel nor the facilities to provide distribution service. It serves only large users at high pressure. The merger will not operate to stifle or reduce present or potential competition with any other company. While the two corporations have been historically separate corporations, there are a number of common stockholders, a majority of the directors are common to both companies, and both of the companies have substantially the same management.

The record shows that the original cost of Southwest's facilities as of August 31, 1961 (including construction work in progress), as it appeared on Applicant's books was $15,322,044 against which a reserve for depreciation had been accumulated in the amount of $2,887,877. Similarly, the book original cost of Nevada's facilities on August 31, 1961, was $7,466,674 and there was an accumulated reserve for depreciation of $1,573,270.

As of August 31, 1961, the capital stock and surplus and long-term debt of Southwest was as follows:

Capital Stock and Surplus:	
Common stock $1 par value issued and outstanding 437,052 shares	$459,784
Cumulative convertible prior preferred stock, $9 par value, $1.20 dividend (voting), issued 96,834	871,506
Capital surplus, restricted against distribution to common stockholders	3,026,781
Earned surplus ($169,087 restricted by bond indenture)	816,442
Cumulative convertible prior preferred stock held in treasury, 15 shares at cost	(323)
	5,174,190
Long-Term Debt:	
First mortgage bonds	5,350,000
Debentures, 6% series due 1978	672,000
6% subordinated sinking fund debentures due 1977	376,000
	6,398,000
Less sinking fund requirements due within 1 year	241,000
	6,157,000

Similarly, capital stock and surplus and long-term debt of Nevada were as follows:

Capital Stock and Surplus:	
Common stock, $1 par value, authorized 1,000,000 shares, issued and outstanding 480,000 shares	$480,000
$1.50 dividend series cumulative preferred stock, $21 par value (redemption and liquidation value $25), authorized 80,000 shares, issued 20,636 shares	433,356
Capital surplus	1,269,799
Earned surplus ($371,530 restricted by bond indenture)	524,585
$1.50 dividend series cumulative preferred stock held in treasury, 830 shares at par	(17,430)
	2,690,310
Long-Term Debt:	
First Mortgage Bonds:	
5% Series due 1973	730,000
5% Series due 1976	2,250,000
5½% subordinated sinking fund debentures due 1976	765,750
	3,745,750
Less sinking fund requirements due within 1 year	250,750
	3,495,000

The acquisition by Southwest of Nevada's properties and resources is described as a statutory merger pursuant to the laws of the State of California. All of the facilities now owned and operated by Nevada will be acquired and then owned and operated by Southwest. Thereafter, the facilities will be used to perform the identical services which they prior thereto will have performed as the property of Nevada. Applicant seeks a continuation in its name of all operative authorizations now outstanding in the name of Nevada and authorization to continue without change all operations, acts, services and sales now being performed or made by Nevada, particularly insofar as the same are subject to the jurisdiction of the Commission under the Natural Gas Act. To this end, Applicant requests that a certificate of public convenience and necessity be issued to it granting the necessary authorizations and, without limitations, substituting Applicant's name in lieu of the name Nevada Natural Gas Pipe Line Company in all operative outstanding certificates of public convenience and necessity and all supplements thereto and amendments thereof heretofore granted to Nevada. Upon approval by the stockholders and the appropriate state and Federal regulatory agencies having jurisdiction in the premises, there will be combined in one corporation all of the property, assets, business rights and interests of Applicant and Nevada and all of such property, assets, business rights and interests of Nevada will become vested in Applicant as the surviving corporation. All of the debts, liabilities and obligations of Nevada will become the debts, liabilities and obligations of Applicant.

Under the terms of the merger agreement the shareholders of Nevada will exchange two shares of the outstanding stock of that company for one share of newly authorized $5 par value convertible preferred voting stock of Southwest. Nevada's $21 par value cumulative preferred will be exchanged share for share for new $21 cumulative preferred voting stock of Southwest. The agree-

ment requires approval by the stockholders of both companies and the stockholders of each class of stock of both corporations have approved the agreement in each instance by a majority of more than 99 percent of all shares voting.

Southwest will, upon the merger becoming effective, have an authorized capital stock consisting of 96,819 shares of $9 par value, $1.20 dividend cumulative convertible prior preferred stock, 19,806 shares of $21 par value, $1.50 dividend cumulative preferred stock, 270,050 shares of $5 par value, $1.00 dividend cumulative convertible preferred stock and 2,000,000 shares of $1 par value common stock.

By order issued November 20, 1961, the Arizona Corporation Commission approved the agreement of merger and authorized Southwest and Nevada to do and perform those things required to be done and performed thereunder. By order dated November 21, 1961, the Public Utilities Commission of the State of California authorized Southwest to enter into and carry out the terms and conditions of the agreement of merger. Although the laws of Nevada do not require formal approval, the testimony is that the Nevada Commission has given informal approval of the proposed merger.

After the merger, the combined capitalization of the two companies will be in the neighborhood of $18,000,000. Normal plant expansion in the present fiscal year will result in total capitalization in excess of $20,000,000. The increased size of the combined company will result in greater financial stability and will enable the company to finance at lower cost. As evidence of this result, the insurance company which holds all of the outstanding mortgage bonds of Nevada and most of the outstanding first mortgage bonds of the Applicant, as well as two-thirds of a series of debentures of the Applicant, has agreed to relax or eliminate certain restrictions in the bond indenture of Nevada. Shortly after the effective date of the merger, the Nevada indenture will be satisfied and discharged and the Nevada bonds outstanding under that indenture will be exchange for new bonds, comparable in interest rates and maturities, issued under the Southwest bond indenture. Certain indenture restrictions will be eliminated upon the merger becoming effective. The evidence indicates that the cost of money to the combined corporation will thus be reduced.

Greater rate and operating flexibility will result from the merger, and it will place the merged company in a more competitive position with respect to other energy sources.

To a growing corporation financing is of paramount importance. Nevada has grown steadily from a system capacity of 20,000 Mcf a day in 1953 to 60,000 in 1961 and again needs increased transmission capacity to meet the market requirements in the Las Vegas area. One of Nevada's largest industrial customers has been partially curtailed every day since the first of December 1961 because Nevada did not have the capacity to serve its firm load. With its present system ceiling of 60,000 Mcf a day, it would not be feasible for Nevada to take on substantial industrial loads. Southwest, too, has grown at a substantial rate and from a management standpoint this growth, about 20 percent a year for the last four years, has presented a serious financing problem.

Combining the two corporations would facilitate the consolidation of management, obviate the necessity to make allocations of management and other functional costs such as rental of office space and the operation and maintenance functions applicable to both companies.

Greater rate and operating flexibility would result from the merger and it would place the merged company in a more competitive position with other energy sources, thus giving the consolidated company a better opportunity to increase its load factor.

The merger will have no effect upon any of Nevada's agreements for the purchase or sale of natural gas except that Southwest will succeed to the rights and obligations of Nevada thereunder. A few of such agreements provide for assignment only with the consent of the other party or parties thereto, but since Southwest will be a successor to Nevada rather than its assignee, such provisions are not expected to be operative.

Since Southwest seeks continuance in its name of all authorizations now outstanding in the name of Nevada and authorization to continue without change all of Nevada's operations, acts, sales and services, Southwest will timely submit, in accordance with the requirements of Section 154.65 of the Commission's Regulations under the Natural Gas Act, a duly executed "certificate of adoption" in the form prescribed by Section 250.4 of such Regulations, of all operative and effective rate filings of Nevada as heretofore filed with the Commission.

The merger will have no effect on any of Southwest's agreements for the purchase or sale of natural gas or upon any of its rate schedules or tariffs on file with the respective commissions having jurisdiction over Applicant.

Since the merger contemplates savings in financing and operational costs, it is not beyond the bounds of reason that Southwest's customers will enjoy lower rates than if the two companies continued to be operated separately.

As has been pointed out, the Commission in its order of January 12, 1962, found it necessary and appropriate in the public interest to take into account, in considering whether to approve the acquisition of the facilities of Nevada by Southwest, the policies and provisions of the anti-trust laws. Staff counsel in this proceeding accordingly directed specific attention to that issue. The question is of peculiar pertinence because of the recent decision of the United States Court of Appeals for the District of Columbia in *People of the State of California* v. *Federal Power Commission* (decided March 30, 1961), 296 F. 2d 348. There the Court held that the Commission in considering whether to approve a transaction must give heed to the policies and provisions of the antitrust laws.

As explained in that decision, the policy of the antitrust laws is to foster free competition. Free competition, of course, is a basic postulate of our free enterprise system and thus the policies of the antitrust laws are founded on the public interest. But, the Court said, free competition is not always in all conditions in the public interest. There are times when monopoly, but regulated monopoly or a measure of controlled monopoly instead, is in the public interest. Thus, in the field of public utilities, monopoly or partial monopoly under public regulation is deemed in the public interest. In such an instance, the principal requirement of the utility is service, and service, the Court recognizes is not a necessary result of competition.[1]

Frequently, regulatory agencies must determine whether one, two or more companies should operate at a given place under given circumstances. Further, the Court had this to say:

> When the Power Commission considers the policies and provisions of the antitrust laws in respect to the transactions of utilities under its jurisdiction, it is not required to—and indeed should not—begin with a general premise

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[1] *Cf.* The language of Justice Brandeis in his dissenting opinion in *New State Ice Company* v. *Liebmann*, 52 S.C. 371, where he said:

> The introduction in the United States of the certificate of public convenience and necessity marked the growing conviction that under certain circumstances free competition might be harmful to the community and that, when it was so, absolute freedom to enter the business of one's choice should be denied.

> that competition is always and under all circumstances in the public interest. * * * The Commission must recognize the policies of the antitrust laws, but it must also recognize its own responsibilities under its own laws.

The foregoing language is construed to mean that the objective and indeed the criteria for the determination of the public interest is, with respect to monopoly, substantially the same under the antitrust laws as under the certificate provisions of the Natural Gas Act. The antitrust laws and the regulatory laws deal with different subject matters.

In that proceeding the Commission found that the public interest would be served in several respects by the merger proposed therein. The combined system would be considerably strengthened by the increase in available gas supplies; development of sources and markets would be stimulated; the merged company would be in a stronger financial position; existing gas supplies could be more effectively used to meet emergencies in periods of peak demand; and, finally, cost saving would be realized that would ultimately be reflected in lower rates. Thus, the Commission weighed the elimination of an apparent potential competitor against the factors which would tend to be beneficial to the consumers and the public.

In the instant case, the evidence shows that there is not now and has never been competition between the two companies; that the combined system would be considerably srengthened financially and thus be enabled to more readily secure financing for obviously needed expansion in the public interest. Opportunities for improvements in load factor would increase. Cost savings would be realized which, under regulation by this Commission, should ultimately be reflected in lower rates to consumers.

We are not here concerned with questions of conspiracy, legal or illegal, the legality or illegality of motives or corporate relationships created for purposes of the advancement of illegal objectives. The basic and controlling question here is the immediate and/or ultimate impact of the proposed transaction upon consumers whose interests are subject to the protection of this Commission and the interests of the public generally.

Nevada is, and heretofore has been, a natural gas company subject to the jurisdiction of this Commission and consequently all of its rates and charges made, demanded or received for or in connection with the transportation or sale of natural gas subject to the jurisdiction of this Commission, and all rules and regulations affecting or pertaining to such rates or charges are subject to the regulation of this Commission. Although Southwest has not been, upon the consummation of the proposed merger, it will be engaged in the transportation of natural gas in interstate commerce and in the sale of such gas in interstate commerce for resale and its rates, charges, classifications and services will be subject to such regulation. The Natural Gas Act places upon this Commission the duty and responsibility to see that all such rates, charges and classifications are just and reasonable and not unduly discriminatory or preferential. There is no evidence in this record that either Nevada or Southwest will have placed themselves in a position less exposed or vulnerable to such regulation. Furthermore, it is clear from the evidence that the contractual provisions underlying the merger are such that there will be no inflation in Southwest's accounts, and, therefore, no basis on which the possibility of higher rates to consumers in the future might be predicated.

The granting of this certificate gives to Southwest, as the consolidated corporation, the right which has heretofore existed in Nevada, namely, the right to transport natural gas from previously existing points of receipt to preexisting points of delivery. Presently Nevada, and after the consolidation, Southwest

will be the only person or corporation having such rights. The existence of such rights do not preclude the granting of identical or broader rights to some other person or corporation should the future public convenience or necessity so require.

Upon review of the evidence of record herein and with specific attention to the question whether the proposed merger "would result in a potential abuse of economic power or the substantial lessening of competition," Staff counsel expressed, in his brief, the opinion that it would be in the public interest to issue the certificate authorizing Southwest to acquire the facilities of Nevada as hereinabove set out.

FINDINGS AND CONCLUSIONS

Upon consideration of the entire record in this proceeding, the evidence adduced and the briefs filed, the Presiding Examiner further finds and concludes that:

(1) Applicant, Southwest Gas Corporation (Southwest) is a California corporation engaged in the local distribution of natural gas in the States of Arizona, California and Nevada.

(2) Nevada Natural Gas Pipe Line Co. (Nevada) is a Nevada corporation with its principal place of business in Las Vegas, Nevada, and is a "natural-gas company" within the meaning of the Natural Gas Act.

(3) The facilities of Nevada hereinbefore described are proposed to be acquired and operated by Southwest, by the merger of Nevada into Southwest pursuant to the Agreement of Merger set forth in the application and described in the evidence herein, and in accordance with the General Corporation Law of the State of California.

(4) The acquired facilities are proposed to be used, as they are presently being used, for the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission; and the acquisition, and operation of these facilities are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) The sales of natural gas made from the facilities of Nevada to be acquired by Southwest by the proposed merger, as more fully described in the application and the evidence herein, will be made in interstate commerce subject to the jurisdiction of the Commission and such sales are subject to the jurisdiction of the Commission and to the requirements of all of the provisions of the Natural Gas Act.

(6) Southwest is able and willing properly to do the acts and perform the services proposed in connection with its acquisition of such facilities of Nevada and to conform to the provisions of the Natural Gas Act, and the requirements, rules and regulations of the Commission hereunder.

(7) The acquisition and continued operation of the facilities proposed to be acquired by the merger of Nevada into Southwest, and the sales of natural gas by Southwest, subject to the jurisdiction of the Commission, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter provided.

(8) Public convenience and necessity require that the general terms and conditions set forth in paragraphs (a), (b) ,(d), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.20) should attach to the certificate hereinafter issued to Southwest and to the exercise of the rights granted thereunder, and that the time within which the facilities authorized by this order shall be acquired and in actual operation should be fixed at sixty days from the date on which this order shall become effective.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal, or review by the Commission on its own motion, as provided in its Rules of Practice and Procedure, that:

(A) A Certificate of Public Convenience and Necessity is hereby issued, subject to all pertinent provisions of the Natural Gas Act and the Commission's Regulations thereunder, including to the extent applicable paragraphs (a), (b), (d), and (e) of Section 157.20 of such Regulations, authorizing Southwest to acquire, by merger, and to operate all of the facilities of Nevada, subject to the jurisdiction of the Commission, which are described in the application of Southwest in these proceedings.

(B) All permits and Certificates of Public Convenience and Necessity heretofore issued to Nevada by the Commission are hereby rescinded as of the effective date of the merger herein authorized; and identical Certificates of Public Convenience and Necessity to those so rescinded, with any amendments or modifications thereof made by the Commission, are hereby issued to Southwest, subject to the pertinent provisions of the Natural Gas Act and the Commission's Regulations thereunder, to be just as effective as if Southwest had originally been issued said certificates; and Southwest is hereby vested with all rights, and charged with all obligations and responsibilities, of Nevada under said rescinded certificates.

(C) The certificates issued in Paragraphs (A) and (B) above shall be void and without force or effect unless accepted in writing within thirty days from the date on which this order becomes effective, and in accordance with the provisions of paragraph (a) of Section 157.20 of the Commission's Regulations under the Natural Gas Act.

(D) The acquisition of Nevada's facilities by Southwest, as authorized in Paragraph (A) hereof, shall be accomplished by Southwest by merging Nevada into it pursuant to the General Corporation Law of the State of California by the taking and completing of the legal steps described in Southwest's application and the evidence herein, within sixty days of the issuance of this Order.

(E) Within thirty days from the date on which this Order becomes effective Southwest shall reissue, in its own name and without other change, all FPC Gas Tariffs of Southwest now on file with the Commission, but excluding agreements between Southwest and Nevada.

EDWARD B. MARSH,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

CONTINENTAL OIL COMPANY, DOCKET NO. G–11024; THE ATLANTIC REFINING COMPANY, DOCKET NO. G–11034; CITIES SERVICE PRODUCTION COMPANY, DOCKET NOS. G–11046, G–15330; TIDEWATER OIL COMPANY, DOCKET NO. G–11049

ORDER DENYING REHEARING AND CLARIFYING OPINION

(Issued March 22, 1962)

Continental Oil Company, The Atlantic Refining Company, Cities Service Production Company, and Tidewater Oil Company, jointly known as CATCO, and The Public Service Commission of the State of New York have filed applications

for rehearing on February 21, 1962, of our Opinion No. 351 and Order of January 22, 1962, 27 FPC 96, issuing permanent certificates of public convenience and necessity for the sale of natural gas from the Cameron Area in the Gulf of Mexico to Tennessee Gas Transmission Company conditioned on a base price of 18.5 cents per Mcf. To a large extent we think that our opinion adequately discusses the points raised by the applicants but the following discussion may make our position clearer.

CATCO objects to our determining the "in lineness" of the proposed price as of the year 1956 when it made its contract with Tennessee. CATCO would have us determine the price line on the basis of the record on remand as of the date of our opinion, January 22, 1962.[1] We agree with CATCO that our function under Section 7(e) of the Act is to determine whether the proposed sale is required by the *present* or *future* public convenience and necessity and that we should not ignore events that have occurred since the first proceeding, but because of the remand our certificate issued January 22, 1962, will replace the one issued in June 24, 1957 and will apply from that day forward. In our opinion, if the price was out of line at the time it was first established in the contract, it is not consistent with the present or future public convenience and necessity, nor with the public convenience and necessity from the time deliveries commenced in 1958.

We found that a price is not in line if it is the highest price or in the highest group of prices. CATCO contends that this constitutes a downward drive of prices. We do not agree. CATCO's reasoning must be that the next price we would approve must necessarily be lower than the 18.5 cent price determined by us here.[2] There is no reason for such an assumption. In any case the prices for the offshore Louisiana area are now subject to our Statement of General Policy issued September 28, 1960, 24 FPC 818, and the Fourth Amendment to it issued October 31, 1961. In the latter we determined that the offshore price should be 19.5 cents per Mcf assuming no taxes. On May 10, 1961, we instituted an area proceeding for the Southern Louisiana area (AR61–2) in which the offshore price could be determined on the basis of a record and hearing.

CATCO's attempts to show that its proposed price is in line rests on evidence relating to periods extending after 1956. The same exhibit cited by CATCO shows that in the period July 1, 1954 to June 30, 1956, all but five of 68 contracts contained base prices of 18.5 cents or below and included 88 percent of the gas. It was not until 1957 and 1958 that the situation changed substantially.

PSC agrees that a price is not in line as of a given time if it is the highest price or in the highest group of prices. It points out, however, that there were no sales between the 18.5 cent price and the highest pre-CATCO price of 20 cents. Of course, we did not intend to establish a rigid formula. In one case there might be one high price we would consider out of line; in another case there might be a high group. In the present case if we examine the two years before the CATCO contract we find there are 5 contracts at 20 cents. Then there is a gap and there are 3 at 18.5 cents, 4 at 18.25 cents, 2 at 18 cents, 17 at 17 cents, 3 at 16.4 cents, 25 at 16 cents, and a few still lower. This, in connection with the other evidence cited in our opinion, indicates that 18.5 cents is in line. It is

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[1] It suggests that a determination would be necessary for intermediate years assuming that a refund were permissible.

[2] CATCO points out that the proposed 21.4-cent price includes 3 mills per Mcf representing the original 3 mill Louisiana Severance Tax. If this tax should be applicable (See Opinion No. 351, p. 5), the tax-free CATCO price, as of the time of the contract would be, in effect, 21.1 cents in the Zone 3 area. This price is still plainly out-of-line under our analysis.

not the highest price but it is close to other lower prices. In another case the pattern of prices may be different, and it is difficult to apply any rigid rule. This is another instance where we believe that the establishment of area rates will prove of great assistance in determining the price required by the public convenience and necessity.

PSC queries as to the meaning of our provision that Tennessee continued to pay a tax reimbursement of 1.5 cents per Mcf for gas produced in Zone 3 pending judicial determination of Federal jurisdiction over the offshore area. It asks whether we mean that the 1.5 cent tax reimbursement is an in-line tax reimbursement of an in-line total initial price or whether it represents the escalated tax reimbursement provision which would be authorized under the Commission's non-certificate practices. If the former, PSC says we are in error because at the time of the contract the total Louisiana taxes were less than 1.5 cents and an "in-line" tax provision for this period would have been one cent per Mcf. If the latter, PSC will offer no objection as the matter is *de minimis*, but will challenge the treatment in another case. We did not intend the 1.5 cent tax reimbursement as an in-line provision as of the time of the contract, but because Louisiana taxes, if applicable, were increased on December 1, 1958, we are of the opinion that the partial tax reimbursement of the tax increases provided in the contract were in the public interest and required by the public convenience and necessity.

Coming to the cost of service, CATCO objects to our finding that the cost of service presentation is limited and falls short of that usually found requisite in a rate case. The cost of service presentation here has been valuable to us and, we do not say that it was inappropriate for the purposes of the proceeding. Nevertheless it is not a complete cost of service and the results must be considered indicative only and not decisive either as showing confiscation or showing that CATCO will make an excessive return. As noted in our opinion the production costs are solely on the basis of one portion of the Cameron area. The Continental exploration costs were used on the company-wide basis although the exploration costs of each company varied by as much as six cents on CATCO's basis of computation.[3] PSC submits that our cost of service computation is generous and overstates the cost. While we agree with PSC that it does not show the necessity for an initial price in excess of 17 cents per Mcf, neither does it show that the price should be as low as 17 cents per Mcf. We think the controversy on this issue shows the necessity for area determined prices that will avoid the need for the presentation of full cost of service evidence in producer proceedings with all the disadvantages set forth in our *Phillips* case.[4]

On allocation of production costs CATCO objects to our use of the gross revenues method even for the purposes of this proceeding, and contends that we should have used the straight Btu method.[5] We do not find that the Btu method, which apportions costs according to the chemical energy in the respective products, is suitable here. The condensate naturally separates from the gas and assumes a different physical form when brought to the surface and the high pressure is reduced. Its use is different and its value per Btu is very different from

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[3] CATCO used a 14-percent rate of return and the Btu method of allocation showing exploration costs as follows: Continental 16.03 cents, Atlantic 14.07 cents, Cities 9.94 cents, and Tidewater 11.02 cents.

[4] 24 FPC 537, affirmed *State of Wisconsin* v. *F.P.C.*, 303 F. 2d 380, CADC No. 16175, decided November 30, 1961. *Cert.* granted May 14, 1962, 369 U.S. 870.

[5] CATCO cites our *Glasell* case, 25 FPC 1071, Docket Nos. G–9278, *et al.*, June 1, 1961, for this proposition, but this proceeding was remanded on February 8, 1962, by the reviewing Court at the request of the Commission.

the gas. The costs to produce these products, as well as to explore for them, were incurred not soley to obtain energy, but with a view to the economic relationships between them as set forth in our *Phillips* case with respect to the allocation of exploration costs. This situation is different from one where a gas stream is brought to a gasoline plant and in an operation designed for that purpose a separation is there made between two products. The cost of the gas stream at the gasoline plant is thus more directly apportionable to the energy content of the products.

We recognize that there are disadvantages in using the revenues method, which we followed, but the relative cost method used in *Phillips* for production costs was not applicable (there being no wells producing liquids alone in the Cameron area). There would have been some logic in using the Btu method modified by the *Phillips* case economic factor of 4. However, if we had done this, less cost would have been allocated to gas than under the gross revenues method.

With respect to income taxes we agree that actual taxes should be allowed but they have not been shown here. It would give a distorted picture to compute theoretical taxes on the production from any given leases in any given year. In certain years a lease will provide deductions in excess of revenues and in other years it will receive revenue in excess of deductions. In determining company tax liability on its total oil and gas production activities the results of operations under all leases must be considered. In our *Phillips* case cited by CATCO in support of using actual taxes, we based our computations on the company's oil and gas producing business. We found $45,000 of "actual" taxes on the basis of our computation out of a total cost of *Phillips'* oil and gas business of $183,569,305 (24 FPC at p. 581).

On rate of return we did not repudiate the *Bluefield* case [6] as contended by CATCO. The rate of return earned by other companies is properly considered, but is not sufficient in itself, for *Bluefield* recognizes that a utility has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises (262 U.S. at pp. 692–693). In *Tennessee Gas Transmission Co.* v. *F.P.C.* 293 F. 2d 761 (CA5), [Fifth Circuit reversed insofar as it set aside interim order 371 U.S. 145 (1962)] an argument with respect to the return earned by other pipelines was made, but the Court pointed out that there was no basis for the assumption that Tennessee was entitled to the same return on book equity which they have historically enjoyed. We considered the rate of return evidence in this record and did not find it inconsistent with using an 11 percent rate of return in our limited cost-of-service computation.

On the question of reserves we did not make a definite finding: [7] the record did not permit us to do so, but whether we took CATCO's estimate of reserves or the examiner's finding, there is nothing to show that the 18.5 cent initial price is in error.

CATCO argues that we have no authority to order refunds of the difference between the 18.5 cent rate determined in our opinion and order and the 21.4 cent rate actually charged. With respect to the period up to November 17, 1959, when the original certificate was vacated the gist of CATCO's argument is that our certificate granted in June of 1957 allowing the 21.4

[6] *Bluefield Waterworks Improvements Co.* v. *P.S.C.*, 262 U.S. 679.

[7] CATCO argues that we were in error in stating that it "adopted" Tennessee's estimate of reserves in the original hearing. However, it was Tennessee's estimate of recoverable reserves of 1,673,929 Mmcf at 14.73 psia that was developed at the first hearing and recited in the brief of Atlantic and Cities Service, adopted by the brief for Continental and Tidewater.

cent rate was voidable, not void, and that the rate schedule[8] filed pursuant to our June 1957 order was the legal rate which the applicants were required to charge, citing *Montana-Dakota Utilities Co.* v. *Northwestern Public Service Co.*, 341 U.S. 246, 251.

In our opinion the original certificate was nullified *ab initio* insofar as it was found defective for lack of an appropriate price condition. The same holds true of the rate schedule filed under that certificate. Section 19(b) of the Natural Gas Act provides that the Court shall have authority to "affirm, modify or set aside" an order in whole or in part. Set aside means to annul, cancel, make void.[9] Pursuant to section 19 the Court of Appeals "vacated" our original order[10] and its action was affirmed by the Supreme Court.[11] The situation differs in *Atlantic Coast Line R. Co.* v. *Florida*, 295 U.S. 301, 311 cited by CATCO. There the Interstate Commerce Commission had increased a rate found to be discriminatorily low, and the carrier thereafter charged the increased rate. Because of a failure to make proper findings the order was adjudged void; a new order was entered, similarly increasing the rate, and this was affirmed. The shippers sought restitution of the increase in charges made while the void increase was on file. The Court held that "void" in this context meant "voidable", and that equity would not countenance restitution. Unlike the situation in the *Atlantic Coast Line* case we are not merely curing a defect of form in the first order and re-establishing the same rate; we have found that the first order arrived at the wrong initial price and that a lower rate is required by the public convenience and necessity.

As observed in the *Atlantic Coast Line* case the refund question must be examined in light of the equities. The equities are in favor of a refund here because the 21.4 cent price was charged by CATCO upon the authority of a certificate whose final validity had not been adjudicated, and which was eventually found to be inconsistent with the public convenience and necessity. We are not awarding reparations, in the sense of investigating an effective rate, finding it unlawfully high and ordering a refund; we are reissuing a certificate of public convenience and necessity in place of the certificate issued in June 1957, but with a price condition which in our opinion is consistent with the mandate of the Supreme Court.

CATCO argues that we failed to consider substantial evidence of record. Contrary to CATCO's contentions we did consider the risks of offshore drilling, and the need to encourage exploration for and the development of gas reserves. In estimating the cost of service we used an eleven percent rate of return which is much higher than could be allowed any pipeline company and includes amounts designed to make producing attractive. The in-line price, which we are allowing, is higher than our estimated cost of service so that it included an even larger amount for the encouragement of gas production. The citation of *United Gas Improvement Co.* v. *F.P.C.*, 283 F. 2d 817 (CA9) for the proposition that pre-CATCO prices are "irrelevant for comparative purposes in other cases" does not seem in point, for here we are determining a price that is required by the public convenience and necessity for CATCO itself.

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[8] The rate schedule filing made May 26, 1958, included the contract itself executed August 17, 1956, plus certain amendatory agreements.

[9] Black's Law Dictionary, Third Ed. (1933); Bouvier's Law Dictionary, Third Revision (1914).

[10] *Public Service Commission of New York* v. *F.P.C.*, 257 F. 2d 717 (CA3).

[11] *The Atlantic Refining Co., et al.* v. *P.S.C.*, 360 U.S. 378.

The Commission further finds:

The assignments of error and grounds for rehearing set forth in the applications for rehearing filed herein on February 21, 1962, by CATCO and PSC set forth no new facts or principles of law which were not fully considered by the Commission when it issued its opinion and order of January 22, 1962, or which having now been considered warrant any change in or modification of such opinion and order except as expressed above.

The Commission orders:

The applications for rehearing of the Commission's Opinion No. 351 and order issued January 22, 1962, filed by CATCO and PSC are hereby denied, but the application of PSC to the extent that it asks clarification of our opinion and order is hereby granted as set forth in the text of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NO. G–16235; PACIFIC NORTHWEST PIPELINE CORPORATION, DOCKET NO. G–16237; COLORADO INTERSTATE GAS COMPANY, DOCKET NO. G–16904

ORDER ON APPEAL AFFIRMING RULINGS OF PRESIDING EXAMINER

(Issued March 22, 1962)

El Paso Natural Gas Company on February 27, 1962, filed an appeal to the Commission from two rulings of the presiding examiner in the above-entitled proceedings.

After the applicants had completed presentation of their cases in chief and had rested, Transwestern Pipeline Company, an intervener, requested that it be allowed 30 days in which to complete the preparation of evidence on the cost of delivering through its existing pipeline larger volumes of gas for use in the southern California market. Counsel for Transwestern stated that certain engineering studies, reserve studies and accounting studies which were needed in that connection had not been completed; that he believed that Transwestern would be able to show that its incremental costs of gas are substantially less than Rock Springs' costs and that a substantial saving to the California consumer will result from full utilization of Transwestern's facilities; and that 30 days was not an unreasonably long period of time. (Tr. 14,592–14,595)

Counsel for El Paso objected to Transwestern's request on the ground that the evidence that Transwestern proposed to present is outside the scope of the issues as delineated by the Commission and requested the examiner to forbid Transwestern to present any of that evidence. El Paso objected also to the allowance of 30 days as requested by Transwestern in which to prepare evidence. (Tr. 14,615–14,619).

The examiner overruled El Paso's objections on both points stating that he considered the position taken by El Paso's counsel with respect to the proposed evidence as being decidedly premature, that there had been no question put to a witness or an exhibit tendered in evidence for the examiner to rule upon, and that then and then alone is the proper time to determine the materiality and relevancy of the evidence which Transwestern will offer (Tr. 14,669). The

examiner ruled also that 30 days was a reasonable period for the presentation of rebuttal evidence by Transwestern and by the City and County of Denver:

> * * * upon the understanding which they have made clear in open hearing that they will do the best they can to transmit to counsel for the applicants and other interveners such portions of their exhibits and evidence as they have ready prior to that time. (Tr. 14,642)

Further citations to the relevant pages of the transcript of proceedings are given in El Paso's appeal and need not be repeated in this order.

Upon careful consideration of the points advanced and arguments made by El Paso in its appeal and by other parties who have filed in support of or in opposition to the appeal, we find that the examiner's rulings from which the appeal was taken were proper and should be affirmed. The matter of using existing pipelines, whether by means of exchange arrangements or otherwise, in connection with bringing additional volumes of natural gas to the southern California market, in the event that we decide that the public convenience and necessity require such additional gas supplies, is definitely an issue in these proceedings and should be fully explored. Affirmative evidence thereon should be presented by the applicants if such evidence is not offered by other parties. Such evidence should include, among other things and without limitation, the location, ownership, age, and physical characteristics of such pipelines and appurtenant facilities; existing and potential delivery capacity and use; additional facilities required to increase delivery capacity to the economic optimum and cost thereof; costs of operation and of gas at delivery points. We find also that the period of time which the examiner allowed for the preparation of evidence by Transwestern and by the City and County of Denver was reasonable and proper.

The Commission orders:

The presiding examiner's rulings hereinbefore referred to are affirmed.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

ORDER ESTABLISHING NATIONAL POWER SURVEY ADVISORY COMMITTEES AND PRESCRIBING PROCEDURES

(Issued March 22, 1962)*

The Federal Power Commission is directed by Section 202(a) of the Federal Power Act (16 U.S.C. 792–825r) to promote and encourage voluntary interconnection and coordination of the nation's electric power facilities in the interest of economy and conservation, and is authorized by Section 311 of the Act to conduct broad investigations covering all aspects of the entire power industry. In order to accomplish these objectives more effectively and in accordance with Executive Order No. 11007 of February 26, 1962 (27 FR 1875), relating to the Formation and Use of Advisory Committees, we have concluded that it is the public interest that National Power Survey Advisory Committees be, and they hereby are established.

1. *Purpose.* The Committees shall advise and make recommendations to the Commission in planning and carrying out the Commission's proposed national power survey.

2. *Selection of Committee Members.* All Committee members and alternates shall be selected by the Chairman of the Commission.

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*Commission determination issued April 7, 1964, continued Committee for additional two years.

3. *Conduct of Meetings.* The Chairman of the Commission, or in his absence, the Vice Chairman of the Commission, or any other full-time employee of the Commission designated by the Chairman of the Commission, shall act as Chairman of Committee meetings and shall be responsible for opening and conducting meetings and for adjourning meetings when, in his judgment, adjournment is in the public interest.

4. *Minutes.* The Chairman of the Commission having made a finding that maintenance of a verbatim transcript would be impracticable and not in the public interest, there shall be kept by the Secretary of each Committee, in lieu thereof, a record of persons present, a description of matters discussed and conclusions reached, and copies of all reports received, issued, or approved by the Committees.

5. *Secretary of the Committee.* The Chairman of the Commission shall appoint a Secretary of each Committee from among the members of the Commission staff who shall be responsible for preparing summary minutes of all Committee meetings, preparing agenda, notifying members of the meetings, and maintaining all records related to organization, membership and operations of the Committees. The Secretary shall be present during all meetings and shall certify the accuracy of all minutes.

6. *Location and Time of Meetings.* Meetings will convene at the call of the Chairman of the Commission at the Office of the Federal Power Commission, located at 441 G St., NW., Washington 25, D.C., unless otherwise directed. Ordinarily, these meetings will be held during the regular working hours of the Federal Power Commission.

7. *Advice and Recommendations Offered by the Committee.* The advice and recommendations of the members of the Committees may be presented to the Commission at Committee meetings either orally or in written form. The advice of all Committees shall be limited to matters relating solely to the planning and carrying out of the national power survey and ultimate decisions based on the Committees' advice or recommendations are reserved to the Federal Power Commission.

8. *Duration of the Committee.* All Committees shall terminate not later than two years subsequent to their date of establishment, unless the Commission determines in writing, not more than 60 days prior to the expiration of such two-year period, that continued existence of a Committee is in the public interest. A like determination by the Commission shall be required not more than 60 days prior to the end of each subsequent two-year period to continue the existence of each Committee thereafter.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

VIRGINIA ELECTRIC & POWER COMPANY, PROJECT NO. 2009

ORDER APPROVING REVISED PROJECT EXHIBIT

(Issued March 22, 1962)

Application was filed on January 30, 1962, by Virginia Electric and Power Company, licensee for major Project No. 2009, for Commission approval of a revised Exhibit K for the Roanoke Rapids development showing certain minor changes in project works within the project boundaries.

The revisions in Exhibit K reflect ties constructed between two transmission lines extending from the Roanoke Rapids Power Station to the licensee's Carolina Substation; the construction of a new short 13.2 kv line from an area feeder outside the project boundary to the power station to provide an emergency source of power for station service in the event the power station is not operating; the relocation of the tailrace barrier from the downstream end of the tailrace to the head of the tailrace; and the removal of the log boom from the reservoir. The relocation of the barrier and the removal of the log boom were previously approved by our order of June 20, 1960.

The Commission finds:

Revised Exhibit K (First Amended) Sheet 1 (FPC No. 2009–25) conforms to the Commission's rules and regulations and should be approved as part of the license for the project, and Exhibit K (FPC No. 2009–10), now part of the license and which has been superseded, should be eliminated from the license for the project—all as hereinafter provided.

The Commission orders:

The revised Exhibit K referred to in the above finding is approved as part of the license for Project No. 2009, and the exhibit referred to in the same finding as being superseded is eliminated from the license for the project.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NO. G–16235; PACIFIC NORTHWEST PIPELINE CORPORATION, DOCKET NO. G–16237; COLORADO INTERSTATE GAS COMPANY, DOCKET NO. G–16904.

ORDER REVERSING RULING OF PRESIDING EXAMINER

(Issued March 23, 1962)

On February 9, 1962, the presiding examiner in the above-styled proceedings overruled objections of counsel for the applicants to a question propounded on cross-examination by counsel for the joint interveners Tennessee California Gas Company and California Gas Transmission Company (Tenn-Cal) to a witness for El Paso Natural Gas Company (El Paso).

The specific question propounded is as follows:

> Q. In other words, as a security arrangement, the financial interests financing that line asked El Paso to escrow or trustee the funds they are paying on behalf of West Coast?

After extensive argument, on two occasions, with respect to the propriety of the question, the examiner later certified this matter on appeal.

The offer made by the cross-examiner in support of his question indicates that its purpose was to elicit further information to show that the project proposed in these proceedings contravened the policy of the antitrust laws to the detriment of the ultimate consumer.

We have examined closely the arguments of counsel and the record to which they have referred during the course of their arguments. We believe that the matter called for by the particular question does not add substantially to the material already in the record and to the offer of direct proof made by Counsel

for Tenn-Cal. On the ground that the question is remote and cumulative, the ruling of the presiding examiner should be reversed.

In determining whether a new project should be authorized, we fully recognize our responsibility to consider the impact of the construction thereof upon present and future rates and whether the ultimate consumer will be adversely affected thereby. We must also consider how proposed sources of present or future supplies and the relationships between all parties concerned may affect those rates. Such matters must be viewed, also, in connection with the policy of the antitrust laws.

In connection with the narrow question presented on appeal, however, we feel that there is already sufficient evidence of record to show El Paso's interest in Westcoast Transmission, Ltd., which is one of the limbs to El Paso's potential source of gas from Canada.

We feel it necessary to state further that we do not consider the ruling of sufficient import to have required an appeal and that, if an appeal were allowed, the presentation of briefs would have been a more expeditious and orderly procedure than the additional argument had on the question for our benefit.

The Commission orders:

The appeal of El Paso Natural Gas Company from the ruling of the presiding examiner overruling the objection of counsel for that Company made at the hearing in these proceedings on February 9, 1962, be allowed and the ruling of the presiding examiner be and is hereby reversed.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

HASSIE HUNT TRUST, OPERATOR, *ET AL.*, DOCKET NO. G–19115; H. L. HUNT, OPERATOR, *ET AL.*, DOCKET NO. G–19116; HUNT OIL COMPANY, DOCKET NO. G–19117; WILLIAM HERBERT HUNT TRUST ESTATE, OPERATOR, DOCKET NO. G–19118; LAMAR HUNT TRUST ESTATE, DOCKET NO. G–19119; GEORGE W. GRAHAM, INC., OPERATOR, *ET AL.*, DOCKET NO. G–19123; PLACID OIL COMPANY, OPERATOR, *ET AL.*, DOCKET NOS. G–19124, G–19125; H. L. HUNT, OPERATOR, *ET AL.*, DOCKET NO. CI61–1221; H. L. HUNT, DOCKET NO. CI61–1282; HASSIE HUNT TRUST, OPERATOR, *ET AL.*, DOCKET NO. CI61–1283; CAROLINE HUNT SANDS, DOCKET NO. CI61–1343; CAROLINE HUNT TRUST ESTATE, DOCKET NO. CI61–1344; LAMAR HUNT TRUST ESTATE, DOCKET NO. CI61–1345; NELSON BUNKER HUNT, DOCKET NO. CI61–1346; LAMAR HUNT, *ET AL.*, DOCKET NO. CI61–1736

ORDER PERMITTING INTERVENTION AND DENYING PETITION FOR DECLARATORY ORDER AND MOTION FOR CONTINUANCE

(Issued March 23, 1962)

On February 28, 1962, in the above-captioned proceedings, Hassie Hunt Trust; H. L. Hunt; Hunt Oil Company; William Herbert Hunt Trust Estate; Lamar Hunt Trust Estate; George W. Graham, Inc.; Placid Oil Company; Caroline Hunt Sands; Caroline Hunt Trust Estate; Nelson Bunker Hunt; and Lamar Hunt (Petitioners) filed a joint protest, petition for declaratory order and motion for continuance of hearing.

On February 16, 1962, the Public Service Commission of the State of New York (PSC) filed a notice of intervention in Docket Nos. CI61–1221, CI61–1282, CI61–1283, CI61–1343, CI61–1344, CI61–1345, CI61–1346 and CI61–1736 in these proceedings.

Petitioners have petitioned the Court of Appeals for the Fifth Circuit for review of certain orders heretofore issued by the Commission in each of the above-captioned proceedings, except in Docket No. CI61–1736. The joint protest and motion for continuance are based upon the contention that, because the certificate applications in these dockets will have been certified to the Court by March 28, 1962, as part of the record on review, the Court will have exclusive jurisdiction over the applications as of that date pursuant to Section 19(b) of the Natural Gas Act (Act), and the Commission will consequently lack statutory authority to take any further action with respect to the applications until completion of court review.

This argument is based upon an erroneous construction of Section 19(b) of the Act. The Petitioners rely on the following pertinent portion which provides that:

> . . . the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of title 28, United States Code. Upon the filing of such petition such court shall have jurisdiction, which upon the filing of the record with it shall be exclusive, to affirm, modify, or set aside such order in whole or in part . . .

This language is clear and unambiguous; it vests the court with exclusive jurisdiction to affirm, modify or set aside the order complained of in the petition for review. There is no mention of jurisdiction over the certificate application or any portion of the proceeding. Section 19(b) refers only to the exclusive jurisdiction of the court to act upon the order which is before it for review and, provided the Commission does not attempt to modify or set aside that order, it in no way interferes with or limits our jurisdiction to go forward with other aspects of the case. Petitioners set forth no logical basis for extending that jurisdiction to the certificate application or any further proceeding thereon which does not involve a contemplated modification of such order. The mere fact that the certificate application is certified to the court, incidental to review, can in no way extend or enlarge the exclusive jurisdiction conferred upon the court by Section 19(b).

Petitioners do not allege that the further hearing now scheduled to commence in the above-captioned proceedings on March 28, 1962, was initiated to alter, modify, or set aside the orders which are before the Court for review, and such is not the case. Those orders were not dispositive of the cases; they are interlocutory and procedural. The scheduled hearing is a continuation of the proceedings as a result of the reversal by the Court of Appeals of the District of Columbia Circuit of our order denying the intervention of PSC.

Petitioners' request for a declaratory order alleges that the Commission has failed to spell out with any exactitude the type of evidence which a producer must adduce in order to support his proposed initial price. The Commission's policy, as reflected in both the Statement of General Policy, No. 61–1, issued September 28, 1960, as amended, and in recent decisions, establishes that the producer applicant, if he is seeking an initial price higher than the "in line" or area price level, has the burden of proving that the higher price is required by the public convenience and necessity. The particular economic facts and circumstances that might prompt a producer to seek a certain initial price are innumerable, varied and within the province of his own knowledge. Because of the myr-

lad factual situations which could confront us, it is most important that the applicant be permitted the greatest possible latitude in determining what evidence is essential to meet his burden of proof. For this reason, we will not predetermine what evidence is necessary in order to prove an initial price but will decide each case on its own merits.

The Commission finds:

(1) The Petitioners have not presented sufficient reason to support their motion for continuance or warrant the issuance of a declaratory order.

(2) It is desirable to allow the Public Service Commission of the State of New York to intervene in these proceedings in order that it may establish the facts and the law from which the nature and validity of its alleged rights and interests may be determined and show what further action may be appropriate under the circumstances in the administration of the Natural Gas Act.

The Commission orders:

(A) The Petitioners' motion for continuance and petition for declaratory order are denied.

(B) The Public Service Commission of the State of New York is permitted to intervene in Docket Nos. CI61–1221, CI61–1282, CI61–1283, CI61–1343, CI61–1344, CI61–1345, CI61–1346 and CI61–1736, subject to the rules and regulations of the Commission. *Provided, however,* That the participation of the intervener shall be limited to matters affecting such rights and interests as may be established; and *Provided, further,* That the admission of the intervener be not construed as recognition by the Commission that it may be aggrieved by any order or orders entered in these proceedings.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CITIES SERVICE GAS COMPANY, DOCKET NO. CP62–148

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 26, 1962)

On December 12, 1961, Cities Service Gas Company (Applicant) filed in Docket No. CP62–148 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the calendar year 1962 at a total cost not to exceed $3,000,000, with no single project to exceed a cost of $500,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

The subject facilities will be financed from cash on hand.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 20, 1962, respecting the matters involved in and the issues presented by the application in this proceeding. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the

hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Cities Service Gas Company, a Delaware corporation having its principal place of business in Oklahoma City, Oklahoma, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of December 28, 1943, in Docket No. G–298 (4 FPC 471).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing pipeline system, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas from producers thereof during the calendar year 1962 as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed purusant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the costs of the facilities so construed, and (f) the names of the independent producers involved. together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(6) The authorization hereinafter granted should be limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed thereunder should be limited to $3,000,000, with no single project to exceed a cost of $500,000.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Cities Service Gas Company to construct during the calendar year 1962 the proposed facilities hereinbefore described (more fully described in the application filed in this proceeding) and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Cities Service Gas Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) Applicant shall submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed hereunder are limited to $3,000,000, with no single project to exceed a cost of $500,000.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

EL PASO NATURAL GAS COMPANY, DOCKET NOS. G–11797 AND G–12580

FINDINGS AND ORDER FURTHER AMENDING ORDERS ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 26, 1962)

On September 14, 1961, El Paso Natural Gas Company (Petitioner) filed in Docket Nos. G–11797 and G–12580 a petition to further amend the certificate orders in said dockets to reflect minor changes in the construction and operation of certain of the field and main line compressor facilities authorized therein.

Among the facilities authorized in Docket No. G–11797 was the addition of one 810 horsepower compressor unit at Vealmoor Compressor Station in Howard County, Texas, and two 1,800 horsepower compressor units at Plains Compressor Station in Yoakum County, Texas. At Vealmoor, Petitioner has installed an additional 800 horsepower unit rather than the unit authorized, because the unit installed was re-rated by the manufacturer from 810 to 800 horsepower. Because it was found to be more economical, a single 3,500 horsepower unit was installed at Plains in lieu of the two authorized 1,800 horsepower units.

Also Authorized in Docket No. G–11797 was the addition of 2,400 compressor horsepower at the Williams Compressor Station in Coconino County, Arizona, which Petitioner proposed to obtain by turbocharging certain existing compressor units. During the initial construction period, turbocharging materials for those units were not available. However, turbocharging materials for other existing units at the Williams Compressor Station were available, obtained, and installed to produce an additional 2,000 compressor horsepower, rather than the 2,400 horsepower authorized. Subsequently, additional turbocharging materials became available and were installed to produce the remaining 400 horsepower. The latter addition was accomplished concurrently with the installation of 6,400 horsepower at the Williams Compressor Station authorized in Docket No. G–12580. Although costs attributable to only 2,000 horsepower were reported in Docket No. G–11797, Petitioner will report the cost of the additional 400 horse-

power as a part of its cost report to be filed in Docket No. G–12580. As a result of the foregoing, Petitioner has installed at the Williams Compressor Station 400 horsepower less than authorized in Docket No. G–11797 and 400 horsepower more than authorized in Docket No. G–12580.

The minor reduction in compressor horsepower at the Vealmoor and Williams Compressor Stations will not impair Petitioner's ability to perform the services certificated for those installations in Docket No. G–11797. The construction phasing for the turbocharging at the Williams Compressor Station has not altered the cumulative horsepower authorized for installation at that location in Docket Nos. G–11797 and G–12580.

The Commission finds:

It is in the public interest and appropriate in carrying out the provisions of the Natural Gas Act to further amend the orders issued in Docket Nos. G–11797 and G–12580 to reflect changes in the construction of certain compressor facilities authorized therein, as hereinbefore described and as more fully described in the petition herein.

The Commission orders:

(A) The Commission's orders issued on March 26, 1958, in Docket No. G–11797, 19 FPC 393, and on November 27, 1959, in Docket No. G–12580, 22 FPC 900, as amended, be and the same are hereby further amended to reflect changes in the construction of certain compressor facilities authorized therein, as hereinbefore described and as more fully described in the petition herein.

(B) In all other respects said orders shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NATURAL GAS PIPELINE COMPANY OF AMERICA, DOCKET NO. CP61–30

ORDER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 26, 1962)

On November 20, 1961, Natural Gas Pipeline Company of America, 26 FPC 146, (Natural) filed a motion to amend the Commission's order of July 11, 1961, in Docket No. CP61–31, issuing a certificate of public convenience and necessity authorizing Movant to construct and operate facilities to increase the daily design sales capacity of its pipeline by 105,000 Mcf (on a billing basis of 1,000 Btu per cubic foot of gas).

The requested amendment would authorize the sale and delivery by Natural of an additional daily contract quantity of 5,400 Mcf of natural gas to Iowa Electric Light and Power Company (Iowa Electric) and an additional daily contract quantity of 19,000 Mcf of natural gas to Northern Indiana Public Service Company (Northern Indiana). These volumes would be in lieu of those authorized, i.e., zero volumes to Iowa Electric and 15,000 Mcf to Northern Indiana. The additional volumes of gas are to be made available, in part, from the expanded system capacity authorized in the above-entitled docket; and, in minor part (270 Mcf), from facilities authorized in Docket No. CP61–185. Both Iowa Electric and Northern Indiana are existing customers of Natural.

Due notice of the filing of the subject motion to amend and opportunity for hearing thereon has been given by publication in the Federal Register on February 27, 1962 (27 FR 1862). No protest or petition to intervene has been filed in this proceeding on the motion.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act, and the public convenience and necessity require that the Commission's order issued on July 11, 1961, in Docket No. CP61–30, should be amended as hereinafter ordered.

The Commission orders:

(A) The Commission's order issued July 11, 1961, in Docket No. CP61–30 is hereby amended so as to permit Movant, Natural Gas Pipeline Company of America, to sell and deliver additional contract quantities of natural gas to Iowa Electric Light and Power Company in the amount of 5,400 Mcf per day and to Northern Indiana Public Service Company a total of 19,000 Mcf per day. These volumes are in lieu of, and supersede, those volumes originally authorized in said order. Service agreements containing these new volumes are to be given an effective date of December 1, 1961.

(B) In all other respects, the order issued July 11, 1961, shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP61–186; SKELLY OIL COMPANY, DOCKET NO. CI61–601

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND ACCEPTING RELATED FPC GAS RATE SCHEDULES FOR FILING

(Issued March 26, 1962)

On January 6, 1961, as supplemented on October 20, 1961, Northern Natural Gas Company (Northern) filed in Docket No. CP61–186 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of a 7,000 horsepower compressor station and a 10-inch pipeline tie-over to connect its existing 10-inch field line with its existing 16-inch transmission line, all in Lea County, New Mexico, and all as more fully set forth in the application, as supplemented.

On October 17, 1960, as supplemented on September 15, and October 18, 1961, Skelly Oil Company (Skelly) filed in Docket No. CI61–601 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the sale of residue gas to Northern from Skelly's Eunice No. 1 and No. 2 Plants in Lea County, New Mexico, all as more fully set forth in the application, as supplemented.

Skelly and Northern have entered into an agreement wherein Skelly has agreed to sell and Northern has agreed to buy additional volumes of residue gas from Skelly's aforementioned natural gasoline extraction plants. Northern is not obligated to purchase in excess of 40,000 Mcf of gas per day above and beyond 6,000 Mcf per day presently dedicated.

Additional facilities are necessary for Northern to receive the additional gas into its transmission system. Northern proposes to use the additional gas to

supplement its total gas supplies for general distribution in its market area and does not propose to enlarge its system salable capacity nor make any additional sales. The proposed facilities are estimated to cost $2,206,880, and will be financed by Northern from funds on hand and cash generated through operations. Northern estimates that 104,881 Mcf of gas will be available to it under the contract.

Skelly has filed the gas sales contract, as amended, concurrently with the application and supplements thereto herein.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 15, 1962, respecting the matters involved in and the issues presented by the applications herein. No protests to the granting of the applications or petitions to intervene have been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Northern Natural Gas Company, a Delaware corporation having its principal place of business in Omaha, Nebraska, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G–280 (3 FPC 967).

(2) Applicant, Skelly Oil Company, is engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission, and is, therefore, a "natural-gas company" within the meaning of the Natural Gas Act.

(3) The facilities to be constructed by Northern, as hereinbefore described and as more fully described in the application, as supplemented, in Docket No. CP61–186, are proposed to be used in the sale and transportation of natural gas in interestate commerce, subject to the jurisdiction of the Commission, as integral parts of Northern's existing pipeline system and the construction and operation thereof by Northern are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The sale of natural gas by Skelly to Northern, as hereinbefore described and as more fully described in the application, as supplemented, in Docket No. CI61–601, will be made for resale in interstate commerce, subject to the jurisdiction of the Commission, and such sale by Skelly is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) Northern and Skelly, respectively, are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(6) The construction and operation of the facilities proposed by Northern in Docket No. CP61–186 and the sale of natural gas proposed by Skelly in Docket No. CI61–601 are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(7) Public convenience and necessity require that the certificate issued hereinafter in Docket No. CP61–186 and the rights granted thereunder be conditioned upon Northern's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record

and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Northern Natural Gas Company to construct and operate the facilities hereinbefore described, all as more fully described in the application, as supplemented, in Docket No. CP61–186, for the transportation and sale of natural gas in interstate commerce as therein set forth, upon the terms and conditions of this order.

(B) The certificate issued by Paragraph (A) above and the rights granted thereunder are conditioned upon Northern's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The time within which the facilities authorized in paragraph (A) above shall be completed and placed in actual operation is hereby fixed at six months from the date on which this order issues.

(D) A certificate of public convenience and necessity be and the same is hereby issued authorizing the sale by Skelly to Northern of natural gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, as hereinbefore described and as more fully described in the application, as supplemented, in Docket No. CI61–601.

(E) The grant of the certificate issued in paragraph (D) above shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or of Part 154 or Part 157 of the Commission's Regulations thereunder, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Applicant. Further, our action in this proceeding shall not foreclose nor prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contracts herein involved. Nor shall the grant of the certificate aforesaid for service to the particular customer involved imply approval of all of the terms of the respective contracts, particularly as to the cessation of service upon termination of said contracts as provided by Section 7(b) of the Natural Gas Act. Nor shall the grant of the certificate aforesaid be construed to preclude the imposition of any sanctions pursuant to the provisions of the Natural Gas Act for the unauthorized commencement of any sales of natural gas subject to said certificate.

(F) The related rate schedules listed below are accepted for filing to be effective on the date indicated. Such acceptance for filing shall not be construed as constituting approval by this Commission of any service, rate, charge, classification, nor any rule, regulation, or practice affecting such service or rate; nor shall this order be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending, or hereafter instituted by or against the Applicants involved. Further, in the event that any document comprising the listed rate schedule was executed on or after April 3, 1961, and contains provisions, either therein or by adoption of the terms and provisions of other agreements, for a change in rate other than those permitted by Section 154.93 of the Commission's Regulations under the Natural Gas Act, such rate

change provisions shall be inoperative and of no effect at law and any tendered rate change under such provisions will be rejected.

Description	Designation	Effective Date
Contract of September 15, 1960	Skelly Oil Company FPC Gas Rate Schedule No. 162.	Initial Delivery.
Assignment (not dated)	Supplement No. 1 to above	Initial Delivery.
Letter Agreement of March 30, 1961	Supplement No. 2 to above	Initial Delivery.
Letter Agreement of March 30, 1961	Supplement No. 4 to Skelly Oil Company FPC Gas Rate Schedule No. 73.	May 7, 1961.
Amendment of October 6, 1961	Supplement No. 5 to above	November 17, 1961.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. G–14562; CONTINENTAL OIL COMPANY, DOCKET NO. G–13680; MAGNOLIA PETROLEUM COMPANY (SOCONY MOBIL OIL COMPANY, INC.), DOCKET NO. G–13827; NEWMONT OIL COMPANY, DOCKET NO. G–13948

ORDER REOPENING PROCEEDING AND SETTING DATE OF HEARING, PERMITTING FILING OF AMENDED APPLICATIONS AND DENYING REQUESTS FOR TEMPORARY AUTHORIZATION, FOR SEVERANCE AND FOR EXTENSION OF TIME FOR FILING EXCEPTIONS

(Issued March 26, 1962)

On January 8, 1962, the Presiding Examiner, after having heard the matters presented in the above-docketed applications, as amended, and briefs having been filed, issued his Initial Decision therein dismissing all of the applications. Tennessee Gas Transmission Company (Tennessee), in Docket No. G–14562, had sought authority to construct and operate facilities extending into the Gulf of Mexico off the coast of Louisiana so as to transport to its main transmission system natural gas to be produced by Tennessee in specified acreage in Vermilion and Cameron Parishes, Louisiana. Tennessee proposed to acquire this specified acreage under a so-called leasehold acquisition agreement from the remaining applicants herein.

On February 1, 1962, Tennessee filed a fourth supplement to its amended application in Docket No. G–14562 along with a motion to reopen the instant proceeding. Tennessee now seeks authority to construct and operate the same facilities heretofore requested but denied by the Examiner. However, instead of acquiring the aforesaid leaseholds and producing the gas, Tennessee now proposes to purchase the gas to be produced from said acreage, on a per Mcf basis from the producer-applicants herein.[1] The proposed initial price is 21.4¢ per Mcf at 15.025 psia with a 2¢ per Mcf periodic escalation every four years.

On February 2, 1962, Continental Oil Company (Continental) and Newmont Oil Company (Newmont) each filed an amendment to their respective docketed applications herein seeking authorization of the above sale to Tennessee. Both applicants, on the same date, also filed requests for the issuance of temporary authorization for the sale now proposed, stating that they would be willing to accept temporary authorization conditioned at a price level not below 19.5¢ per Mcf at 15.025 psia, provided that such condition applied only until a determination of a rate for the South Louisiana area is made in the proceeding in Docket

[1] Continental Oil Company, Socony Mobil Oil Company, Inc., and Newmont Oil Company (MCN).

Nos. AR61–2, *et al.*, or until a hearing is had on the now amended proposal and a decision rendered thereon. Conjunctively, a joint and several petition was filed by Continental and Newmont to reopen the instant proceeding along with a motion to sever their respective docketed applications herein and consolidate them with the South Louisiana area rate proceeding in Docket Nos. AR61–2, *et al.*

Similarly, Socony Mobil Oil Company, Inc. (Socony), filed on February 2, 1962, a petition to reopen the instant proceeding along with a motion to sever its docketed application in this proceeding and consolidate it with Docket Nos. AR61–2, *et al.*, *supra*. On February 8, 1962, Socony also filed an amendment to its docketed application herein along with a request for temporary authorization. Socony seeks the same authorization and relief as that now being sought by Continental and Newmont.

Answers in opposition to one or more of the aforesaid pleadings were filed by United Gas Improvement, Long Island Lighting Company and Public Service Commission of the State of New York, all interveners herein. All of these answers put the initial price, proposed in the amended filings, in issue.

We also note that exceptions were filed by the Pennsylvania Public Utilities Commission and the staff of this Commission to that part of the Examiner's Initial Decision wherein the Examiner found:

> * * * The evidence in this proceeding adduced by Tennessee, and taken as evidence adduced by Tennessee on its behalf and on behalf of the MCN companies, is sufficient to prove that a per-Mcf sale of the Blocks 46 and 64 gas involved in the contract of August 26, 1960, at an initial price of 19.5 cents per Mcf at 15.025 psia is in accordance with the public interest and is required by the public convenience and necessity.[2]

In this regard, requests for the extension of time in which to file exceptions to the Examiner's Decision were filed on February 28, 1962, by the interveners, Consolidated Natural Gas System Companies,[3] Public Service Electric and Gas Company and the Columbia Companies.[4]

The Commission finds:

(1) The matters now presented in this proceeding are interrelated and should be heard on a consolidated basis.

(2) Sufficient cause has not been shown why Docket Nos. G–13680, G–13827, and G–13948 should be consolidated with Docket Nos. AR61–2, *et al.*

(3) Good and sufficient reasons have not been shown why temporary authorization should be granted to Continental, Socony, and Newmont.

(4) The manner now proposed for the acquisition of the MCN gas is materially different from the manner previously proposed and disposed of by the Examiner in his Initial Decision of January 8, 1962, in these dockets. In view of our acceptance of these amended filings, the matters disposed of by the Examiner are no longer before us.

The Commission orders:

(A) The motions for severance filed by Continental, Socony, and Newmont are hereby denied.

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[2] Initial Decision, Finding (5).

[3] The East Ohio Gas Company, Hope Natural Gas Company, Lake Shore Pipe Line Company, New York State Natural Gas Corporation, and The Peoples Natural Gas Company.

[4] United Fuel Gas Company, The Manufacturers Light and Heat Company, and The Ohio Fuel Gas Company.

(B) The motions for consolidation of Docket Nos. G–13680, G–13827, and G–13948 with Docket Nos. AR61–2, *et al.*, are hereby denied.

(C) The requests for temporary authorization filed by Continental, Socony, and Newmont in their respective docketed applications are hereby denied.

(D) The requests for an extension of time in which to file exceptions are hereby denied.

(E) The proceeding in Docket Nos. G–14562, G–13680, G–13827, and G–13948 is reopened and remanded to the Presiding Examiner for further hearing.

(F) A hearing be held in this reopened proceeding commencing on May 14, 1962, at 10:00 a.m. (e.d.s.t.), in a hearing room of the Federal Power Commission, 441 G St., NW., Washington, D.C. All parties heretofore permitted to intervene in these docketed applications are deemed interveners in the reopened proceeding. Further protests or petitions to intervene may be filed with the Federal Power Commission, Washington 25, D.C., in accordance with the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10) on or before April 16, 1962.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Charles R. Ross.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. CP61–194: NEW YORK STATE NATURAL GAS CORPORATION, DOCKET NO. CP61–198; TOWN OF LIBERTY, MISSISSIPPI, DOCKET NO. CP61–208; THE WIND GAP DIVISION OF BANGOR GAS COMPANY, DOCKET NO. CP61–222; THE HUGHESVILLE DIVISION OF JERSEY SHORE GAS & HEATING COMPANY, DOCKET NO. CP61–223; NEW YORK STATE NATURAL GAS CORPORATION, DOCKET NO. CP61–237; TEXAS EASTERN TRANSMISSION CORPORATION, DOCKET NO. CP61–238; NEW YORK STATE NATURAL GAS CORPORATION, DOCKET NO. CP61–238; TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. CP61–238

ORDER DENYING WITHDRAWAL OF PLEADINGS

(Issued March 26, 1962)

These proceedings were initiated on January 23, 1961, with the filing by Transcontinental Gas Pipe-Line Corporation (Transco) at Docket No. CP61–194 and New York State Natural Gas Corporation (New York Natural) at Docket No. CP61–198 of separate applications for certificates of public convenience and necessity pursuant to Section 7(c) of the Natural Gas Act. By notice dated July 19, 1961, those two applications were consolidated with five other Section 7 matters and the consolidated proceeding was set down for hearing to commence on September 25, 1961.

In conformance with the notice of July 19, 1961, three pipeline companies, namely, Tennessee Gas Transmission Company (Tennessee), Southern Natural Gas Company (Southern), and Atlantic Seaboard Corporation (Seaboard) and 18 distribution companies filed petitions, and were permitted, to intervene. Notices of intervention were filed by two state commissions. The names of some 50 attorneys appear of record and it may be concluded that including counsel, witnesses, technicians and others, well over 100 persons have been required to devote some or all of their time and attention to this proceeding.

Except for Tennessee, all of the interveners favored the granting of the authorizations sought or, at least, did not oppose such requested authorizations.

Tennessee intervened in Docket Nos. CP61-194, CP61-198, CP61-237 and CP61-238, alleging an interest based on "competition." Tennessee further alleged that the storage proposals here involved are but another step towards ultimately excluding Tennessee from participation in the growth of the Philadelphia, New Jersey, and New York City market areas presently served concurrently by the two pipeline applicants and by Tennessee; that "Consolidated", (Consolidated Natural Gas System, the parent company of New York Natural) "has more than ample storage capacity to satisfy its storage needs for the present and indefinite future;" that "New York Natural has excess storage capacity in its presently developed storage pools which is more than ample to cover the proposed service;" and that "it appears that Consolidated and New York Natural have agreed * * * to purchase * * * ACQ gas from Texas Eastern and Transco with provisions to buy * * * more, while at the same time cutting back on lower priced gas from Tennessee" to the "financial injury" of Tennessee.

Tennessee did not present a direct case but participated quite extensively in the cross-examination of all but one of New York Natural's witnesses. The hearing was concluded on November 2, 1961.

A motion by Transco to omit the intermediate decision procedure was opposed by Tennessee and denied by the Commission.

Thereafter, briefs were filed by New York Natural, Transco, Tennessee, a number of the distributor applicants and Staff counsel. Tennessee filed a 95-page brief strenuously opposing the issuance of the certificates sought by New York Natural at Docket Nos. CP61-198, CP61-237, and CP61-238 and those sought by Transco at Docket Nos. CP61-194 and CP61-238. In that brief Tennesse referred to Transco in the following language:

> Obviously, Transco by its own admission is using the device of now requesting facilities for which it has no need. Of course, these excess facilities will be reflected as part of Tranco's rate base cost. Present customers will thus pay for them without any concomitant use, all contrary to the public interest. The next step in the device will be to seek authority to use such excess facilities to provide some further service with the supporting claim that no facilities are needed to render that service.
>
> Effective regulation must condemn any such practice, particularly when such a device places one pipeline in a position to render service in the New York-New Jersey area without the necessity of asking for further certificate authority to build additional facilities and a competitor to render like service must obtain that authority and build the required facilities. Such a device falls at least within the periphery of unfair competition.

On February 15, 1962, Tennessee filed with the Commission a document as follows:

NOTICE OF WITHDRAWAL

> Tennessee Gas Transmission Company (Tennessee), pursuant to Section 1.11(d) of the Commission's Rules of Practice and Procedure, hereby withdraws from further participation in the above-captioned proceedings. In addition, Tennessee hereby requests permission to withdraw all pleadings it has heretofore filed in the above-captioned proceedings.

Section 1.11(d) of the Commission's Rules of Practice and Procedure provides that a notice of withdrawal shall set forth the reasons therefor and requires the express permission of the Commission to withdraw any pleading in any proceeding in which a hearing has been commenced.

The Presiding Examiner issued his decision in these proceedings on March 2, 1962. In Footnote No. 1 on Page 5 of his decision, the Examiner takes cognizance of Tennessee's filing and states that his decision was in the final stages of

preparation at the time of this filing and that Tennessee's position, as reflected in its 98-page brief, and elsewhere, had been carefully analyzed. The Examiner states that his decision disposes of the issues presented as of the time of the hearing and that Tennessee's withdrawal does not alter the results so reached.

Contrary to the requirement of Section 1.11(d) of the Commission's Rules, Tennessee's notice of withdrawal does not set forth therein any reason therefor. Before, during and after the hearings, Tennessee has consistently opposed the grant of the instant applications. Tennessee has made serious charges in these proceedings in an attempt to show that the grant of the applications is not in the public interest. The record has been made, and as evidenced by the presiding examiner's decision, Tennessee's charges were given serious consideration. When delivery is thus imminent it is too late to abort.

After its persistent efforts extending over such a prolonged period of time, it is difficult to understand how the public interest can now be served by permitting Tennessee to withdraw. That the conditions which up to February 15, 1962, Tennessee claimed to exist could have disappeared so quickly, if they previously existed, seems doubtful. We believe that this case is ripe for decision and must be decided on the basis of the record made.

The Commission orders:

Tennessee's request to withdraw all pleadings it has heretofore filed in these proceedings be and the same hereby is denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NORTHERN NATURAL GAS COMPANY, DOCKET NOS. G–19040, G–19041, RP61–23 AND RP62–6

ORDER DENYING MOTION FOR ORDER FIXING HEARING AND PRESCRIBING PROCEDURE

(Issued March 27, 1962)

On February 27, 1962, Northern Natural Gas Company (Northern) the respondent in these consolidated proceedings,[1] filed a motion requesting the Commission to fix a date certain for a hearing to be held for the limited purpose of requiring Fuels Research Council, Inc., National Coal Association, United Mine Workers of America, Mid-West Coal Producers Institute, Inc., Upper Lake Docks Coal Bureau, Inc., and The Chesapeake and Ohio Railway Company (Coal Interveners) to support by substantial evidence, prior to their further participation in any conferences or hearings in these proceedings, the allegations of possible aggrievement and economic injury set forth in the petition to intervene filed by the Coal Interveners in these proceedings. Numerous answers in support of Nothern's motion were filed by customers of Northern.

On March 9, 1962, the Coal Intervenors filed their answer in opposition to Northern's motion in which they aver that "this is but another in a series of attempts by Movant to force the Coal Intervenors to present evidence prematurely on an issue the Presiding Examiner and the Commission have held was raised by Movant and as to which Movant has the burden both as to proceeding

[1] These proceedings now involve only the issue of rate design as it applies to the relative levels of the commodity charges and demand charges of the rates provided for in the settlement agreement approved by order of the Commission issued December 21, 1961, 26 FPC 901.

and proof. See 23 FPC 580; 23 FPC 708; 22 FPC 164 at 177." [2] We agree with the Coal Interveners that the present motion filed by Northern is designed to achieve substantially the same result as its motion filed herein on July 21, 1961, and which we denied by order issued August 21, 1961.

In the order issued herein on December 21, 1961, aforementioned, we provided for further hearing on the issue of rate design. On February 23, 1962, a notice was issued reconvening the hearing for said purpose on March 27, 1962. At said hearing Northern or its customers may rest, or may desire to present further evidence on the issue of rate design.[3] In any event the Natural Gas Act (Act) places the burden of supporting the proposed design of rates upon Northern. Thereafter, the submission of evidence to support any contention that the proposed design of rates would cause them aggrievement and economic injury may be made by the Coal Interveners. To grant Northern's motion would be contrary to the requirements of the Act and would disrupt the orderly procedure of the hearing.

The Commission finds:

Due and timely administration of the Commission's functions under the Natural Gas Act require that the motion filed by Northern herein on February 27, 1962, be denied.

The Commission orders:

The motion filed herein by Northern on February 27, 1962 be, and the same is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CITIES SERVICE GAS COMPANY, DOCKET NO. CP62-123

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 28, 1962)

On November 16, 1961, Cities Service Gas Company (Applicant) filed in Docket No. CP62-123 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of certain minor "budget-type" facilities during the calendar year 1962, including branch lines and meter and regulator equipment, to make miscellaneous temporary and permanent direct sales of natural gas from Applicant's existing pipeline system, all as more fully set forth in the application.

The maximum total cost of the facilities for which authorization is sought is $97,500, with no individual project to exceed a cost of $15,000. The cost of said facilities will be paid out of treasury cash.

Applicant estimates that it will have approximately 15 requests for temporary sales in 1962 by road construction contractors and other operators of temporary plant locations, with each request involving an estimated average sale of 35,000 Mcf of gas annually and an average cost to Applicant of approximately $2,500 per installation required for such sale.

Also, Applicant anticipates aproximately 30 requests for direct sales to consumers on a permanent basis, each request involving an average sales volume of

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[2] Footnote omitted.

[3] It is not here intended to preclude the parties from conferring on possible settlement of the issue involved.

approximately 81,000 Mcf of gas annually and an average cost of approximately $2,000 per instalaltion.

The estimated total volume of gas involved under this application for a maximum of 45 customers is 2,955,000 Mcf of gas, all fully interruptible, with minor exceptions, which volumes will not appreciably affect Applicant's gas reserves or service to existing customers.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 20, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Cities Service Gas Company, a Delaware corporation having its principal place of business in Oklahoma City, Oklahoma, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of December 28, 1943, in Docket No. G–298 (4 FPC 471).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) The construction during the calendar year 1962 and the operation of the facilities and delivery of natural gas as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(4) Applicant is able and willing properly to do the acts to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(5) The authorization granted hereinafter should be limited to construction during the calendar year 1962, and the total expenditures for facilities authorized to be constructed should be limited to a maximum of $97,500, with no single project to exceed a cost of $15,000. Further, this authorization should limit sales to not more than 15 direct industrial customers on a temporary basis, and not more than 30 new direct industrial customers on a permanent basis, with the total volume of natural gas authorized not to exceed 2,955,000 Mcf per year.

(6) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(7) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit on or before March 1, 1963, a statement under oath showing (a) complete information as to the actual construction, (b) the cost of each installation, (c) name and location of each customer, (d) actual facilities installed for each customer, (e) expected date of termination of service to temporary customers, (f) expected annual revenues, and (g) expected annual deliveries to each customer.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Cities Service Gas Company to construct and operate natural gas facilities and to sell natural gas as hereinbefore described, and as more fully described in the application in this proceeding upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities authorized to be constructed are hereby limited to a maximum of $97,500, with no single project to exceed a cost of $15,000. Further, sales of natural gas under this authorization are hereby limited to not more than 15 direct industrial customers on a temporary basis, and not more than 30 new direct industrial customers on a permanent basis, with the total volume of natural gas involved not to exceed 2,955,000 Mcf per year.

(D) Applicant shall submit on or before March 1, 1963, a statement under oath showing (a) complete information as to actual construction, (b) cost of each installation, (c) name and location of each customer, (d) actual facilities installed for each customer, (e) expected date of termination of service to temporary customers, (f) expected annual revenues, and (g) expected annual deliveries to each customer.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

PACIFIC POWER & LIGHT COMPANY, DOCKET NO. E-7024

ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTAGE BONDS

(Issued March 28, 1962)

Pacific Power & Light Company (Applicant), a corporation organized under the laws of the State of Maine and doing business in the States of California, Oregon, Washington, Wyoming, Montana and Idaho, with its principal business office at Portland, Oregon, filed an application on February 19, 1962, as supplemented on February 27 and March 8 and 13, 1962, for an order, pursuant to Section 204 of the Federal Power Act, authorizing the issuance of $35,000,000 principal amount of First Mortgage Bonds, due 1992, to be sold at competitive bidding.

Applicant proposes to issue the Bonds under its Indenture of Mortgage and Deed of Trust, dated as of July 1, 1947, to Guaranty Trust Company of New York (now Morgan Guaranty Trust Company of New York) and Oliver R. Brooks (Wesley L. Baker, successor) as trustees, as heretofore supplemented and as to be further supplemented by a proposed Thirteenth Supplemental Indenture to be dated as of April 1, 1962.

On or about March 29, 1962, Applicant proposes to invite sealed, written bids for the purchase of the Bonds, by newspaper publication and by distribution of a Form of Bid, together with a statement of the terms and conditions relating thereto and a recital of the terms of purchase which will constitute the purchase

agreement herein. All bids, whether from a single bidder or from a group of bidders, must be submitted on the Form of Bid provided by the Applicant and each counterpart must be signed by the bidder, or by the representative in the case of a group of bidders. Each bid must be for the purchase of all the Bonds and must specify: the coupon rate, which shall be a multiple of ⅛th of 1 percent; the price exclusive of accrued interest to be paid to Applicant for the Bonds, which price shall be not less than 98½% nor more than 102¾% of the principal amount thereof; and, that Applicant shall be paid the amount of the accrued interest on the Bonds from April 1, 1962, to the date of payment therefor and delivery thereof. Each bid must be accompanied by a certified or official bank check or checks in the aggregate amount of $1,050,000, payable in New York Clearing House funds.

Unless postponed all bids for the proposed issuance of Bonds must be presented to Applicant before 11:00 a.m., New York Time, on April 11, 1962, at Room 2033, Two Rector Street, New York 6, New York. Unless Applicant rejects all bids, which it reserves the right to do, or excludes a bid or bids for reasons specified in the statement of the terms and conditions, it will accept the bid which will provide it with the lowest annual cost of money.

Applicant will utilize the proceeds of approximately $35,000,000 to be obtained from the proposed issuance of Bonds, together with proceeds of approximately $19,900,000 to be obtained from the proposed issuance of additional Common Stock (Docket No. E–7025), to repay an estimated $42,000,000, principal amount of Promissory Notes, which Applicant has already issued or will have issued under the authority granted by this Commission in Docket No. E–7011,[1] and toward the cost of its current construction program, which is expected to require the expenditure of approximately $44,000,000 for 1962 and $56,000,000 for 1963.

Applicant's estimated construction expenditures for 1962 and 1963 include $250,000 for completion of the Iron Gate Hydroelectric project in 1962, and $3,000,000 in 1962 and $15,000,000 in 1963 for installation of a 150,000 kw unit at the Dave Johnston Steam Plant at Glenrock, Wyoming. Applicant allocates $5,500,000 to the Salt Caves Hydroelectric project—subject to obtaining required regulatory authority permits. Other items, for 1962 and 1963, respectively, are: electric transmission facilities, $14,265,000 and $6,600,000; other facilities, $5,031,000 and $4,500,000; electric distribution facilities, $15,383,000 and $17,000,000; additions to steam heating, water and telephone utility systems, $1,827,000 and $1,540,000; and, other plant facilities, surveys and investigations, $1,845,000 and $5,160,000.

Written notice of the application has been given to the Public Utilities Commission of California, the Idaho Public Utilities Commission, the Public Service Commission of Montana, the Public Utility Commissioner of Oregon, the Washington Utilities and Transportation Commission, and the Public Service Commis-

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[1] By order issued October 6, 1961, in Docket No. E–7011, Applicant was authorized to issue up to $45,000,000, principal amount of Promissory Notes, under a Credit Agreement of August 15, 1961, between Applicant and various banks. The notes were to be dated as of the dates of the borrowings; were to mature eleven months after dates or on March 31, 1963, whichever should be earlier; and, were to bear interest at the New York prime rate. The notes were to be issued for the following purposes: to discharge notes aggregating $10,000,000 issued by The California Oregon Power Company and assumed by Applicant in the merger of California Oregon into Applicant; to discharge notes aggregating $18,000,000 issued by Applicant to obtain construction funds; and, to provide additional funds required for Applicant's construction program. The application for the issuance of the notes stated that Applicant's construction program had an estimated cost of $30,034,000 in the last six months of 1961 and an estimated cost of $12,000,000 in the first three months of 1962.

sion of Wyoming, and to the Governor of each of those States. Notice of the application has also been given by publication in the Federal Register on March 8, 1962 (27 FR 2259), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before March 21, 1962 with the Federal Power Commission, Washington 25, D.C. No protest or petition or request to be heard in opposition to the granting of the application has been received.

On March 13, 1962, the Public Utilities Commission of California; on March 6, 1962, the Idaho Public Utilities Commission; on March 7, 1962, the Public Service Commission of Montana; on March 16, 1962, the Public Utility Commissioner of Oregon; on March 16, 1962, the Washington Utilities and Transportation Commission; and, on March 8, 1962, the Public Service Commission of Wyoming approved the proposed issuance of $35,000,000 principal amount of bonds, in the manner and for the purposes set forth above.

The Commission finds:

(1) Applicant, a Maine corporation, owns and operates facilities for the transmission and sale at wholesale of electric energy which is transmitted between the States of Oregon and Washington, from the State of Oregon to the State of California, and between the States of Montana and Wyoming, and is consumed outside the States in which it is generated. These facilities are in addition to and do not include facilities used for the generation of electric energy or facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or facilities for the transmission of electric energy consumed wholly by the transmitter. Applicant is, therefore, a public utility within the meaning of that term as used in Section 204 of the Federal Power Act.

(2) The proposed issuance and sale of Bonds, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204(f) of the Act; and the proposed issuance of securities is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

(5) The period of public notice given in this matter is reasonable.

The Commission orders:

(A) The proposed issuance and sale of Bonds, upon the terms and conditions and for the purposes specified in the application, as described above, are authorized, subject to the provisions of this order.

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the

Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

(C) This authorization shall expire unless the transaction hereby authorized is consummated within 60 days from the date of issuance of this order.

(D) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(E) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States with respect to any securities to which this order relates.

Commissioner Morgan *dissents* on the grounds that the period of public notice was unreasonably short, that the notice of application was deficient and that the construction of one of the facilities to be financed from the proceeds of the securities authorized herein—the Oregon-California inter-tie as proposed by Applicant—has not been shown to be compatible with the public interest and should not be authorized pending policy decisions relative to such an inter-tie scheduled by the current session of the Congress. A Commission opinion and Commissioner Morgan's dissent will be issued later.[2]

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

PACIFIC POWER & LIGHT COMPANY, DOCKET NO. E–7025.

ORDER AUTHORIZING THE ISSUANCE OF COMMON STOCK

(Issued March 28, 1962)

Pacific Power & Light Company (Applicant), a corporation organized under the laws of the State of Maine and doing business in the States of California, Oregon, Washington, Wyoming, Montana and Idaho, with its principal business office at Portland, Oregon, filed an application on February 19, 1962, as supplemented on February 27 and March 8 and 13, 1962, for an order, pursuant to Section 204 of the Federal Power Act, authorizing the issuance of up to 696,695 shares of Common Stock, par value $3.25 per share.

Applicant proposes to offer up to 696,695 additional shares of Common Stock to its Common Stockholders of record at the close of business on March 26, 1962, for subscription on the basis of one share of additional Common Stock for each twenty shares of outstanding Common Stock held on such record date, with a supplementary subscription privilege if the number of shares held on the record date is not evenly divisible by twenty or is less than twenty. Rights to subscribe for the additional Common Stock will be evidenced by transferable subscription warrants. The subscription price per share will be determined by Applicant's Board of Directors shortly before the proposed offering date, and will be fixed in relation to, and at an appropriate discount from the then market price of Applicant's presently issued and outstanding Common Stock. The subscription offer will expire at 3:30 p.m., New York Time, on May 1, 1962. In addition, Applicant proposes to sell to underwriters any shares of additional

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[2] Commission opinion, No. 354, printed on p. 623; Commissioner Morgan's dissent appears at p. 631.

Common Stock for which Applicant's Common Stockholders do not subscribe, at the same price at which shares of additional Common Stock will be offered under the subscription offer, and to fix by competitive bidding the compensation of the underwriters for their commitments to purchase the unsubscribed Stock.

On or about March 29, 1962, Applicant proposes to invite sealed, written bids for the purchase of the unsubscribed Stock by newspaper publication and by distribution of a form of bid and a form of purchase agreement, together with a statement of terms and conditions relating thereto. All bids, whether from a single bidder or a group of bidders, must be on the form of bid furnished by Applicant and must be for the purchase of all of the unsubscribed Stock. Each bid must specify, among other things, (1) the price per share to be paid to Applicant for the unsubscribed Stock, which price shall be the same as the subscription price to Applicant's Common Stockholders; and, (2) the aggregate amount to be paid by Applicant to the bidder or bidders as compensation for their commitments and obligations in connection with the purchase by them of the unsubscribed Stock.

Unless postponed, all bids for the purchase of the unsubscribed Stock must be submitted to Applicant at Room 2033, Two Rector Street, New York 6, New York, before 11:00 a.m., New York Time, on April 5, 1962. Each bid must be accompanied by a certified or official bank check or checks in the aggregate amount of $250,000, payable in New York Clearing House funds. Each of the bidders must agree that in case any shares of unsubscribed Stock are acquired and sold prior to the expiration of thirty days following the day upon which the subscription period expires for a price in excess of the purchase price plus $1.00 per share, the bidder will pay to the Applicant, in addition to the purchase price, a sum equal to 50% of such excess. Unless Applicant rejects all bids, which it reserves the right to do, or excludes a bid or bids for reasons specified in the statement of terms and conditions relating to bids, Applicant will accept the bid which provides for the lowest aggregate amount of compensation to be paid by Applicant to the bidder or group of bidders.

Applicant will utilize the proceeds of approximately $19,900,000 to be obtained from the proposed issuance of additional Common Stock, together with proceeds of approximately $35,000,000, to be obtained from the proposed issuance of First Mortgage Bonds (Docket No. E–7024), to repay an estimated $42,000,000, principal amount of Promissory Notes, which Applicant has already issued or will have issued under the authority granted by this Commission in Docket No. E–7011,[1] and toward the cost of its current construction program, which is expected to require the expenditure of approximately $44,000,000 for 1962 and $56,000,000 for 1963.

Applicant's estimated construction expenditures for 1962 and 1963 include $250,000 for completion of the Iron Gate Hydroelectric Project in 1962, and

[1] By order issued October 6, 1961, in Docket No. E–7011, Applicant was authorized to issue up to $45,000,000, principal amount of Promissory Notes, under a Credit Agreement of August 15, 1961 between Applicant and various banks. The notes were to be dated as of the dates of the borrowings; were to mature eleven months after dates or on March 31, 1963, whichever should be earlier; and, were to bear interest at the New York prime rate. The notes were to be issued for the following purposes: to discharge notes aggregating $10,000,000 issued by The California Oregon Power Company and assumed by Applicant in the merger of California Oregon into applicant; to discharge notes aggregating $18,000,000 issued by Applicant to obtain construction funds; and, to provide additional funds required for Applicant's construction program. The application for the issuance of the notes stated that Applicant's construction program had an estimated cost of $30,034,000 in the last six months of 1961 and an estimated cost of $12,000,000 in the first three months of 1962.

$3,000,000 in 1962 and $15,000,000 in 1963 for installation of a 150,000 KW unit at the Dave Johnston Steam Plant at Glenrock, Wyoming. Applicant allocates $5,500,000 to the Salt Caves Hydroelectric Project—subject to obtaining required regulatory authority permits. Other items, for 1962 and 1963, respectively, are: electric transmission facilities, $14,265,000 and $6,600,000; other facilities, $5,031,000 and $4,500,000; electric distribution facilities, $15,383,000 and $17,000,000; additions to steam heating, water and telephone utility systems, $1,827,000 and $1,540,000; and, other plant facilities, surveys and investigations, $1,845,000 and $5,160,000.

Written notice of the application has been given to the Public Utilities Commission of California, the Idaho Public Utilities Commission, the Public Service Commission of Montana, the Public Utility Commissioner of Oregon, the Washington Utilities and Transportation Commission, and the Public Service Commission of Wyoming, and to the Governor of each of those States. Notice of the application has also been given by publication in the Federal Register on March 8, 1962 (27 FR 2259), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before March 21, 1962 with the Federal Power Commission, Washington 25, D.C. No protest or petition or request to be heard in opposition to the granting of the application has been received.

On March 13, 1962, the Public Utilities Commission of California; on March 7, 1962, the Idaho Public Utilities Commission; on March 6, 1962, the Public Service Commission of Montana; on March 16, 1962, the Public Utility Commissioner of Oregon; on March 16, 1962, the Washington Utilities and Transportation Commission; and on March 9, 1962, the Public Service Commission of Wyoming approved the proposed issuance and sale of Common Stock by Applicant in the manner and for the purposes described above.

The Commission finds:

(1) Applicant, a Maine corporation, owns and operates facilities for the transmission and sale at wholesale of electric energy which is transmitted between the States of Oregon and Washington, from the State of Oregon to the State of California, and between the States of Montana and Wyoming, and is consumed outside of the States in which it is generated. These facilities are in addition to and do not include facilities used for the generation of electric energy or facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or facilities for the transmission of electric energy consumed wholly by the transmitter. Applicant is, therefore, a public utility within the meaning of that term as used in Section 204 of the Federal Power Act.

(2) The proposed issuance of Common Stock, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204(f) of the Act, and the proposed issuance of Common Stock is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance of Common Stock, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

(5) The period of public notice given in this matter is reasonable.

The Commission orders:

(A) The proposed issuance of Common Stock, upon the terms and conditions and for the purposes specified in the application, as described above, is hereby authorized, subject to the provisions of this order.

(B) The proposed issuance and sale of Common Stock at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of the Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegram as contemplated by Section 34.9 of the Regulations;

(ii) The Commission, by further order, shall have approved the subscription price per share to be received by Applicant for the Common Stock and the compensation to be paid to underwriters under the proposed arrangement as described above.

(C) This authorization shall expire unless the transactions hereby authorized are consummated within 60 days from the date of issuance of this order.

(D) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of costs, or any other matter whatsoever which is now pending or which may come before this Commission.

(E) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States in respect to any securities to which this order relates.

Commissioner Morgan *dissents* on the grounds that the period of public notice was unreasonably short, that the notice of application was deficient and that the construction of one of the facilities to be financed from the proceeds of the securities authorized herein—the Oregon-California inter-tie as proposed by Applicant—has not been shown to be compatible with the public interest and should not be authorized pending policy decisions relative to such an inter-tie scheduled by the current session of the Congress. A Commission opinion and Commissioner Morgan's dissent will be issued later.[2]

PACIFIC POWER & LIGHT COMPANY, DOCKET NOS. E-7024 AND E-7025

OPINION ON AUTHORIZING ISSUANCE OF SECURITIES

(Issued April 17, 1962)*

Syllabus

1. Commission *finds* issuance of securities herein compatible with the public interest and emphasizes its lack of jurisdiction over construction of facilities by private electric companies. P. 625.
2. Finding the plain purpose of Sec. 204 is to prevent issuance of securities which might impair a company's financial integrity or ability to perform its public

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* Designated Commission Opinion No. *354*.

[2] Commission's opinion No. 354 printed next below. Commissioner Morgan's dissent appears at p. 631. Further dissent by Commissioner Morgan *infra* p. 1388.

utility responsibilities, Commission states that in testing a security issue by statutory standards it must be satisfied that object is lawful and within corporate purposes. P. 626, 628.

3. Commission puts aside consideration of political controversy concerning disposition of Bonneville surplus, noting it is not for this Commission to exercise role of Congress as arbiter of such matters since Congress has yet to delegate that authority. P. 628.
4. Discussing contention that construction of line at 500 kv represents a "gamble," Commission observes that any anticipation of future growth is a gamble, and failure to anticipate such growth may be a worse gamble. P. 628.
5. Company decision to prepare line for possible future availability of Bonneville power found an exercise of business and managerial judgment for which Commission should not substitute its own. P. 629.
6. Considering the facts currently before it, Commission finds it would be a serious abuse of power to require a hearing and thus delay this security issue. P. 629.
7. Notice found adequate, not unreasonably short, and in no wise inconsistent with regular practice in these matters. P. 630.
8. Approval of securities is not tantamount to approval of Klamath Falls line, or any other facility, and implies no opinion or conclusion on question whether, how or by whom Bonneville power should be transmitted to California. P. 630.
9. Commission *authorizes* issuance of securities under Section 204 of the Federal Power Act. P. 623; 630.

Commissioner Morgan *dissenting.*
Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

By the Commission.

The central question in this case is whether, under Section 204 of the Federal Power Act,[1] approval of the security issues proposed by Pacific Power and Light Company should have been withheld because one of the many facilities to be financed thereby, the northern half of a transmission line running a distance of approximately 110 miles from Klamath Falls, Oregon, to Round Mountain, California, is to be designed and constructed so that it can be operated at 500 kv when and if 500 kv terminal facilities are provided, although it is to be operated initially at only 230 kv. There is no question that the line is fully justified as a 230 kv line.[2] The narrow issue, therefore, is whether, in exercising our jurisdic-

[1] The pertinent language of that Section, contained in Subsection (a) thereof, is as follows:

> No public utility shall issue any security, or assume any obligation or liability as guarantor, indorser, surety, or otherwise in respect of any security of another person, unless and until, and then only to the extent that, upon application by the public utility, the Commission by order authorizes such issue or assumption of liability. The Commission shall make such order only if it finds that such issue or assumption (a) is for some lawful object, within the corporate purposes of the applicant and compatible with the public interest, which is necessary or appropriate for or consistent with the proper performance by the applicant of service as a public utility and which will not impair its ability to perform that service, and (b) is reasonably necessary or appropriate for such purposes. * * *

[2] "All state and federal authorities are agreed that a 230 kv line is justified and would be useful in the proposed location" (dissenting opinion).

tion over security issues, we should make an independent assessment of the wisdom of the decision of management to invest now the additional amounts required to construct the facility in such a way as to enable it to be operated at a higher voltage in the future.

On February 19, 1962, Pacific Power and Light Company (Applicant) filed applications for authorization to issue $35,000,000 principal amount of first mortgage bonds and up to 696,695 shares of common stock, par value of $3.25 per share.[3] Applicant will use the proceeds of approximately $19,900,000[4] to be obtained from the issuance of the common stock, together with the proceeds of the bonds, to repay $42,000,000 in promissory notes and will apply the balance toward the cost of its present construction program, which is expected to require the expenditure of approximately $44,000,000 for 1962 and $56,000,000 for 1963. Applicant is a successful enterprise, with over $189,000,000 of capital stock and surplus in a total capitalization of $584,499,000, as of December 31, 1961.

Applicant's 1962–1963 construction program is composed of a multiplicity of items, including hydroelectric projects, a new generating unit in a steam plant, electric distribution facilities, additions to steam heating and water and telephone utility systems, and ten transmission lines. Of the total program for 1962–1963, amounting to $100,000,000, $5,000,000 will be used for the Klamath Falls-Round Mountain line.[5] A substantially smaller amount, estimated at $1,500,000, is attributable to the extra cost involved in building the line in such a way that its capacity can subsequently be enlarged by conversion to 500 kv. The line in question will interconnect with the system of Pacific Gas & Electric Company, which will build the southern portion. The record indicates that the new intertie will provide for the exchange of energy between the two systems and will be available for use by the Bonneville Power Administration or other utility companies in the Pacific Northwest. A letter-agreement between Pacific Power and Light and Pacific Gas & Electric, dated January 5, 1962, and filed with the Commission as a rate schedule for each company, provides for the building of a 500 kv intertie to be operated at 230 kv until such time as both parties agree that 500 kv operation is economically justified, and for the sale and exchange of electric services.[6]

Our staff made a careful examination of the applications and the attached exhibits and filed a detailed report with the Commission recommending that they be approved.[7] There were no petitions to intervene in these proceedings, and no timely objections to the applications were received from any source. The security issues had the prior approval of the state utilities commissions of California, Oregon, Washington, Wyoming, Montana and Idaho. The matter was considered at length by this Commission at its meeting of March 23, 1962. On the basis of the applications and the staff's recommendations, and in light of the policy of the Commission to encourage public utilities under its jurisdiction to anticipate future loads and to establish and strengthen inter-regional

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[3] The applications were supplemented on February 27, March 8, and March 13, 1962.

[4] This was the estimate at the time of our approval of the initial order for the additional shares of common stock. By reason of a decline in the market price of the Applicant's outstanding common stock, the additional shares of common stock produced net proceeds of about $18,000,000.

[5] In using this term, we refer to the northern half of the line, *i.e.*, the portion which Applicant will build.

[6] The filing was completed on February 23, 1962. By letters of March 30, 1962, we allowed the rate schedules to go into effect as of the following day. We note that the January 5 letter-agreement is attached as Exhibit F to the dissenting opinion.

[7] We reject the suggestion in the dissenting opinion that the Commission was importuned to make undue haste in its disposition of the applications.

transmission interconnections, a majority of the members were satisfied that the statutory standards had been met and that the purposes for which the securities were being issued were compatible with the public interest. However, in order to give further consideration to Commissioner Morgan's differing view, it was decided to postpone final action until the next meeting. At the Commission meeting of March 28, 1962, the applications were once again the subject of extended discussion. All members adhered to their earlier views and on March 28, 1962 we issued orders authorizing the proposed security issues.

It should be emphasized that the surveillance exercised by the Commission under Section 204 is far more limited in scope than that we would exercise if, for example, we were issuing certificates of public convenience and necessity for the construction of facilities. Congress has *not* given the Commission certificate jurisdiction in this area. Indeed, a provision which would have granted us such authority was deleted from H.R. 5423, one of the bills which culminated in the Federal Power Act. In explaining this deletion, the relevant committee report pointed out that:

> While it may ultimately be found desirable to adopt a provision of this kind, the Committee is of the opinion that for the present there is no imminent danger of excessive extensions that would prove disadvantageous to consumers.[8]

The specific provisions of Section 204 make it a particularly unsuitable vehicle for comprehensive licensing-type regulation such as that exercised by this Commission under Section 7 of the Natural Gas Act. Under its provisions, for example, had Applicant elected to finance the construction of its transmission facility out of surplus or from the proceeds of a short-term loan, it could have built the line without so much as notifying the Commission. Again, subsection (f) of Section 204 specifically exempts those companies "organized and operating in a State under the laws of which its security issues are regulated by a State commission." By virtue of this provision, this Commission would have had no jurisdiction over the present security issues if Applicant had happened to be incorporated not in Maine but in one of the states in which it operates and in which security issues of domestic utilities are subject to scrutiny by the state commission. Thus, any securities issued by the company building the southern half of the Kalmath Falls-Round Mountain line would not come before this Commission. Furthermore, under Section 318, a security issue which is subject to the regulation of the Securities and Exchange Commission under the Public Utility Holding Act is withdrawn from the jurisdiction of this Commission. Under Section 204(e) our authority is further restricted, for it does not extend to notes of less than a year's maturity aggregating less than 5% of the company's outstanding securities. If Congress had intended Section 204 to do service as a grant of certificating authority, it would hardly have confined the exercise of that authority to the relatively few companies which are not exempted from that Section.

The plain purpose of Section 204 is to prevent the issuance of securities which might impair the company's financial integrity or its ability to perform its public utility responsibilities. The Senate Committee report on the bill which included the present Section 204 stressed that "control over capitalization of operating utilities is plainly an essential means of safeguarding the public against unsound financial practices which make impossible the proper and most economic performance of public utility functions."[9] The concern with "financial

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[8] Senate Report No. 621, Senate Committee on Interstate Commerce, 74th Cong., 1st Sess. (1935), p. 20.

[9] See Senate Report No. 621, Senate Committee on Interstate Commerce, 74th Cong., 1st Sess. (1935), p. 50.

practices" is further indicated by the fact that the criteria for approval of security issues in Section 204(a) are copied almost verbatim from Section 20a of the Interstate Commerce Act,[10] a measure which was enacted as part of the Transportation Act of 1920 in an effort to put an end to abuses which had threatened many railroads with bankruptcy. For several years prior to 1920, the Interstate Commerce Commission, in response to resolutions passed by the Senate and requests by the House of Representatives, had conducted numerous investigations in the financial dealings of certain carriers. The theme of its diagnosis of the railroad problem was that "a most prolific source of financial disaster and complication to railroads in the past has been the desire and ability of railroad managers to engage in enterprises outside the legitimate operation of their railroads, especially by the acquisition of other railroads and their securities." [11] It was to cure this evil that the Commission recommended that "every interstate railroad should be prohibited from expending money or incurring liability or acquiring property not in the operation of its railroad or in the legitimate improvement, extension or development of that railroad" and that no securities be issued by an interstate railroad except for those purposes and without the approval of the Federal Government.[12]

The leading historian of the Interstate Commerce Commission summed up the purposes of Section 20a as follows: [13]

> While this extension of the Commission's authority was designed, indirectly, to protect the investing public against the dissipation of railroad resources through faulty or dishonest financing, its dominant purpose was to maintain a sound structure for the rehabilitation and support of railroad credit, and for the consequent development of the transportation system. It aimed to render impossible the recurrence of the various financial scandals, with their destruction of confidence in railroad investment, which had become notorious, and to prevent the subordination of the carrier's stake as transportation agencies to the financial advantage of alien interests.

It is apparent that, in modelling Section 204 upon Section 20a of the Interstate Commerce Act, Congress must have had similar objectives.[14]

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[10] 41 Stat. 494; 49 U.S.C. § 20a.

[11] The New England Investigation (No. 4845), 27 I.C.C. 4560, 616 (1913).

[12] *Ibid.*

[13] 1 Sharfman, *Interstate Commerce Commission*, 190 (New York 1931).

[14] The two state decisions cited in the dissent are inapposite. In the Massachusetts case, 62 PUR NS 238; 64 N.E. 2d 640, the State Commission held that the issuance of preferred stock in exchange for common stock was for the sole purpose of furthering the financial interests of persons in 98% control of the company and that, in its judgment, this was not a "reasonably necessary" purpose in the furtherance of the company's public utility business. In the Virginia case, the State Commission held, at 86 PUR NS 136, that, under the different language, coverage, and legislative history of its Act, a Commission order authorizing the issuance of securities is equivalent to a certificate of public convenience. The State Commission then applied a different test then that set forth for an order under Section 204(a), which is not equivalent to a certificate of public convenience and necessity, as pointed out above and as the dissenting opinion concedes.

The dissent also cites *Pacific Power and Light Co. v. Federal Power Commission*, 111 F. 2d 1014 (9th Cir., 1940) as support for a broad reading of the statutory phrase "compatible with the public interest." The holding in that case, however, was that the phrase "consistent with the public interest," which appears in Section 203 and which the court equates with the concept of compatibility, "does not connote a public benefit to be derived or suggest the idea of a promotion of the public interest." The court notes that "it is beyond our immediate purpose to enquire into the precise nature of the interests to be safeguarded by the Commission in passing upon these applications;" yet that is precisely the question at issue here.

In testing a security issue by the statutory standard, the Commission must satisfy itself, of course, that the object is lawful and within the corporate purposes. Beyond that, we must inquire whether the contemplated investment would impair the company's ability to perform its normal functions as a public utility. The Commission might look to whether the investment is so improvident, frivolous, or speculative, that it threatens to squander the corporate substance without reasonable hope of return. By no stretch of reasoning can the construction of the Klamath Falls-Round Mountain line be fitted into one of these categories.

The dissenting view that the Commission should have withheld its approval appears to rest upon two grounds: (a) that the line is politically controversial, particularly in that it could be used to take Bonneville power away from the Northwest if public authorities were to authorize the sale; and (b) that the construction of a line at a voltage of 500 kv represents a "gamble" that Congress will eventually decide to make the Bonneville surplus available for transmission by a privately owned intertie of which this line will be a segment. We not only can but must, put aside the consideration that there may be controversy concerning the disposition of Bonneville's surplus. Whether a publicly owned interconnection should be constructed, whether such interconnection would meet the growing demand for power in the region and thus remove any economic justification for Applicant's proposed expansion of the intertie, and whether Bonneville power should be made available to Applicant for transmission to California, are not for us to decide. It is not for this Commission to exercise the role of Congress as arbiter of these competing claims. That responsibility Congress has yet to delegate.

The remaining question, then, is whether, from an economic standpoint, the extra investment required to make the facilities capable of carrying a voltage in excess of initial requirements—an investment incontrovertibly within the lawful corporate purposes of the Applicant—represents a totally improvident business decision. Any anticipation of future growth is a gamble, and failure to anticipate such growth may be a worse gamble. The electric industry, above all, is one in which making provision for future expansion is customary and prudent. We have no reason to think the "gamble" in this case, that is, the balancing of the carrying charges on the additional investment against the additional costs or losses which will be incurred in the future if the capacity of the facility cannot be expanded when and if needed, is unusual or atypical. Even if the future usefulness of the added investment is contingent upon moving Bonneville power, we cannot say that this is not a contingency Applicant is entitled, and perhaps compelled, to consider. To conclude otherwise is to arrogate to ourselves the right to determine how and by whom Bonneville power should be transmitted.

The movement of Bonneville power, moreover, is not the sole justification for making provision now for a later expansion of capacity. The enormous and continuing growth of the power industry makes it of doubtful wisdom to attempt to restrain electric utilities from taking measures to anticipate future need for greater capacity. This Commission estimated only last January that the demand for electric energy in 1980 will be 3.75 times the requirements in 1960, reflecting a continuation of the industry's recent trend of doubling almost every ten years. The supply of energy needed to meet the demand in the Pacific Northwest and Pacific Southwest areas will come from a variety of sources. In view of the industry-wide tendency toward the use of higher voltages, there is no occasion for surprise that the company has prepared its line, having a life expectancy of upwards of 50 years, for the growing demands of the future. We repeat, however, that even were we to assume with the dissent that the project would be

underutilized if Bonneville power were not obtainable, that fact alone would not justify the Commission in withholding its approval of this security issue. So long as there is a significant possibility that Congress will ultimately decide to make some Bonneville power available for transmission over the Applicant's line—and such possibility manifestly exists—this Commission is in no position to deny that the decision to prepare the line for that eventuality was an exercise of business judgment for which we should not attempt to substitute our own.

The dissenting opinion urges that the Commission should have scheduled a hearing. We declined to do so because we did not see how a hearing would illuminate any material issue. The political questions now confronting Congress would not properly be before us. The nature of the Klamath Falls-Round Mountain line was known, as were the contingencies affecting its future use. No amount of testimony would enable us to predict that future use with accuracy or warrant us in exercising jurisdiction over security issues in such a way as to "second-guess" what is essentially a managerial decision.

It should also be observed that procedures for considering security issues must be expeditious if, in view of changing marketing conditions, utilities are to be able to raise the money needed to carry out their responsibilities. In the present case, no objections were raised to the purposed issue. No person, public or private, sought timely intervention.[15] It would be a serious abuse of power for this Commission to require a hearing and thus delay a $55,000,000 security issue, merely because a small fraction of the proceeds are to be devoted to the construction of facilities which, at extra cost, are susceptible of improvement to enlarge their capacity for a future use which may not materialize. It would be an even more serious abuse of power were we to hold up this security issue merely because questions relative to the disposition of Bonneville's power are politically controversial.

Although we believe that the above considerations are dispositive of this case, we wish to point out that the construction of a high capacity interconnection between the two regions is in harmony with the results of studies of electrical interconnections made by our staff, the Bonneville Power Administration and the Department of the Interior. Such studies were made by our staff in 1950[16] and 1953[17] and show that an interconnection between the electric utility systems in California and the Pacific Northwest would be economically feasible and desirable. In 1960 the Bonneville Power Administration submitted to the Senate Committee on Interior and Insular Affairs a study[18] of possible interconnections between the Pacific Northwest and California. The Bonneville study noted that a proposed intertie between Applicant's predecessor and Pacific Gas and Electric similar to the one here involved would be less costly than an interconnection, then considered, between the federal systems. In commenting on this report in a letter of April 6, 1960, to the Senate Committee, the Chairman of this Com-

[15] The dissent observes that on March 27, 1962, the Commission received a telegram from the Chairman of the State of Washington Utilities and Transportation Commission requesting that we qualify any approval granted so as to prevent the transmission of federally generated power until Congress has acted. The thrust of the telegram goes to political and policy considerations with respect to the use of the line which this Commission cannot consider in a security case. No question was raised as to the economics of the facility or the soundness of the Applicant's financing program. The telegram, moreover, was superseded and withdrawn by a later letter.

[16] Study of an Interconnection between the Electric Systems in the Pacific Northwest and California, Federal Power Commission, February, 1950, pp. 26–27.

[17] Report on Feasibility of California—Oregon 230 kv Interconnection, Federal Power Commission, March 1953, pp. 66–67, 69–72.

[18] Study of High Voltage Electrical Interconnection between the Pacific Northwest and California, Bonneville Power Administration, February 1960, p. 62.

mission stated that the findings of the Bonneville Power Administration indicate that a high voltage interconnection between the Pacific Northwest and California would be desirable and economically feasible regardless of whether the regional facilities were constructed and financed by the Federal Government or private interests. As recently as December 15, 1961, a special task force of the Department of the Interior submitted a report [19] recommending that immediate steps be taken to interconnect the electric generating plants of the Pacific Northwest and Pacific Southwest by lines having a voltage of either 750 kv d-c or 500 kv a-c. Later, in a press release of January 17, 1962 (Appendix C to the dissenting opinion) the Bonneville Power Administrator stated that the plans of Applicant and Pacific Gas & Electric "for a 110-mile 500-kv California intertie are consistent with engineering recommendations of our [Bonneville] Task Force report on a Pacific Northwest-Pacific Southwest intertie."

The dissenting opinion raises a question as to the adequacy of our notice and the length of the notice period. The notice procedure in these cases was in nowise inconsistent with the Commission's regular practice in these matters. In each of the present proceedings, a notice was prepared, describing the securities, setting forth the amounts involved, and stating that the proceeds of the proposed issues would be applied to the payment of outstanding notes and the promotion of the Applicant's construction program. These notices were in the form which has been customary in this agency for twenty-seven years. They did not, to be sure, describe the items in the program as set forth in the voluminous applications. The notices recited, however, that any person desiring to be heard or make protest should do so on or before March 21, 1962, and that the applications were on file and available for public inspection. The notices were dated and sent on March 1, 1962, along with copies of the applications, to the State Commissions of Oregon, Wyoming, Washington, California, Montana and Idaho. The notices were also sent to the Governors and Senators of each of those states and were published in the Federal Register on March 8, 1962, 27 FR 2259. The covering letters to the State Commissions invited the attention of the Commissions to our Plan of Cooperative Procedure, asked whether the Commissions desired to engage in such procedure, and, if not, whether they had any comments or suggestions. The letters to the Governors also asked for comments or suggestions.

A notice in the Federal Register could not, as a practical matter, reproduce the full applications and exhibits thereto. As observed above, the notice advised that all of the documents were available for public inspection. In our view, therefore, the notice was adequate.

Nor was the notice period unreasonably short. All persons were on notice as of March 8, 1962. Certainly, thirteen days, *i.e.*, until March 21, 1962, was an adequate period within which to file a protest or to declare a desire to be heard.

Since the security-issue jurisdiction of this Commission does not embrace a certificating authority, it follows that the approval of the issuance of the securities is not tantamount to an approval of the Klamath Falls-Round Mountain line, or any other facility. Our action in this case implies no opinion or conclusion on the questions whether, how or by whom Bonneville power should be transmitted to California.

Commissioner Morgan *dissents*. Commissioner Woodward *did not participate* in these proceedings.

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[19] Pacific Northwest-Pacific Southwest Extra-High Voltage Common Carrier Interconnection, Special Task Force of U.S. Department of Interior 5–6 (December 15, 1961).

MORGAN, Commissioner, *dissenting:*

"To be, not merely to seem" must be the objective of every regulatory agency deserving of public confidence and respect. A Commission content with mere seeming, as in this case, substitutes ceremony and ritual for that perceptive, vigilant guardianship of the public interest expected of the great regulatory commissions of the United States.

In this order, which seemingly is concerned only with a routine security issue, the staff and majority of the Commission seem to have dealt alertly with all those technical details possibly entailing later difficulty or unnecessary public expense. The "findings" of the majority seem to indicate that thorough investigations were made at both State and Federal levels. Thus the unknowing reader of this order would never suspect the truth: that there has been no meaningful investigation of all the proposed construction to be financed by this security issue by any agency at any level. Who, reading this order, would imagine that no member of the Commission and no member of the staff is presently able to attest from his own knowledge whether any of the projects are in fact "compatible with the public interest" as the law plainly requires and as the order blandly recites?

What private citizen or public official, after reading the order—or, for that matter, after reading the preliminary public Notice of Application[1] circulated among the various Commissions and Governors of the States in which Pacific Power & Light Company operates—would dream that one of the projects proposed to be financed by this issue of securities is an inadequate, highly controversial, and financially questionable substitute for the extra-high-voltage intertie between the Bonneville Power Administration and the Central Valley project in California recently proposed by the Department of the Interior and scheduled for consideration by the current session of Congress?

Does a public notice which fails to notify the public concerning a fact of that magnitude actually offer "opportunity for hearing" under the Federal Power Act? I hold that it does not.

While applicant had publicly discussed its proposed line in a general way by means of press announcement as long ago as last January, neither the general public nor public officials in the affected States regarded the proposal as a device for exporting BPA surplus to California or understood that the proposed construction was involved in the finance issue here under discussion. Thus the Commission's Notice of Application, addressed to Governors and Utility Commissions in the affected States, seemed—but only seemed—to notify them of an "opportunity for hearing" on an important issue. That notice states:

> Any person desiring to be heard or to make any protests with reference to said application should on or before the 21st day of March 1962, file with the Federal Power Commission, Washington 25, D.C., petitions or protests in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10). The application is on file and available for public inspection.

The difference (and the importance of the difference) between the Commission's Notice of Application and a genuine public notice is amply illustrated by the following telegram, dispatched and received while the order was still under consideration as the direct result of my telephone call on March 26, 1962, in-

[1] Appendix A attached hereto.

forming the Chairman of the State of Washington Utilities and Transportation Commission exactly what was contained in the pending application. The telegram, addressed to all Commissioners, was received at 8:40 a.m., March 27, 1962.

> Re your Dockets E–7024 and E–7025 it is requested that FPC give full consideration to position of Pacific Northwest area that no means be provided for the transmission of Federally generated electricity outside present service area Bonneville Power Administration unless and until proper Congressional safeguards be first provided this area. As early as April 1959 in hearings before the Senate Irrigation and Reclamation Subcommittee stated opposition to any California tie-line until such adequate safeguards existed. We therefore respectfully request that in acting on foregoing dockets FPC qualify any approval granted so as to limit any expenditures for interconnection to capacity not in excess of power resources of applicant exclusive of Federally generated power until Congress can fully consider required safeguards.

Does all this throw a new light on the majority's recital, contained in the order, that, on various dates immediately following distribution of the Notice of Application to the Utility Commissions of the States in which PP&L operates, each of those States approved the security issue with no reservations as to the use of the funds raised? It clearly seems so to me—particularly in the case of those States, Oregon and Washington, whose Commissioners testified before the Senate against any intertie proposal such as is now before us.

This seemingly routine financial matter, decided without a hearing and upon the basis of applicant's representations and assertions alone, actually is deeply involved in a controversy which has been raging with increasing intensity for nearly 15 years. It is the most important matter affecting the people of Washington, Oregon, and California to come before the Commission during the incumbency of any of its present members. In its ultimate implications this issue is perhaps as important to the States of the Pacific Northwest as any development since construction of the first Federal main-stream dam across the Columbia more than 25 years ago.

In the light of these facts, I am persuaded that the "period of public notice given in this matter" was unreasonably short, and that the Notice of Application published and circulated by this Commission was gravely deficient in that it conveyed not the slightest inkling of the serious issues actually involved. Further, I am persuaded that the Commission has not, in actual fact, found that all of the proposed construction is "compatible with the public interest" as required by law, for the reasons that:

(a) the applicant has not shown that there is or will be enough non-Federal power to load the intertie in question here; and

(b) the availability of surplus Federal power—which might make the line economical—depends upon a policy decision that must be made by the Congress.

These being the facts, and they are the facts, it was not only premature but impossible for the staff and the majority to "find" that all aspects of the proposal are "compatible with the public interest." I suggest there has been no such finding, that no record exists to support such a finding and that, to those who know and understand the relevant circumstances, the alleged "finding" does not possess even the semblance of reality.

Although no adequate record has been made in this proceeding, there is a voluminous public record, most of it contained in Committee prints and hearings of

the United States Senate,[2] concerning various proposals for marketing seasonally-surplus Columbia River power in California by means of physical interconnection to be built either by privately-owned companies or by the Federal government. Discussion of such an intertie goes back at least as far as 1948.

During the intervening years, every consideration of such an intertie has involved complex problems posed by extension of the marketing area of BPA and by the likelihood of conflicts between the Pacific Northwest and the Pacific Southwest over the possible use of the "preference clause" to export power from the Pacific Northwest which is *not* surplus to that area, but is, in fact, badly needed there.

As a consequence of these long-continued discussions, all Senators and Governors, as well as all Public Utility Commissioners of the Pacific Northwest States, and, in addition, both Senators and the Governor of California, are on record in opposition to any physical interconnection involving the sale of Bonneville power to California-Oregon Power Company (now a part of Pacific Power & Light Company) or to Pacific Gas and Electric Company, or to any other public or private agency in California, unless and until protective legislation is adopted by the Congress effectively quieting all controversy with respect to such exports of power to California.

On July 21, 1960, the Senate Committee on Interior and Insular Affairs adopted a resolution[3] setting forth the foregoing facts and requesting the Secretary of the Interior to:

(a) "* * * continue to suspend negotiations looking to the sale and transfer of surplus power or energy from the Pacific Northwest to California," pending completion of surveys and preparation of protective legislation, and

(b) "* * * submit to the Committee for consideration at the next session of Congress a draft of proposed legislation designed to guarantee consumers in the Pacific Northwest States first call on power generated by Federal agencies in that region, as requested by the Governors of the Pacific Coast States."

Let us dispense with theoretical discussions of the doctrine of separation of powers and the question whether a single Committee of the Senate has authority to control the policies of an agency such as BPA through Committee resolution: the pragmatic fact is that such a resolution, coming from that particular Committee and backed by every Governor and Senator from the states involved (as well as at least two of the Utility Commissions of the states), is a resolution which the Interior Department regards as binding upon it. In compliance, it has suspended negotiations concerning the sale of BPA power in California and

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[2] (a) Hearings before the Subcommittee on Irrigation and Reclamation of the Committee on Interior and Insular Affairs, United States Senate, Eighty-Sixth Congress, First Session, on the Bonneville (Pacific Northwest)-California Intertie, April 8 and 9, 1959.

(b) Committee Print of the Committee on Interior and Insular Affairs, United States Senate, titled "Pacific Northwest (Bonneville)-California Intertie," May 3, 1960.

(c) Hearing before the Subcommittee on Irrigation and Reclamation of the Committee on Interior and Insular Affairs, United States Senate, Eighty-Sixth Congress, Second Session, on the Pacific Northwest (Bonneville)-California Intertie, May 5, 1960.

(d) Hearing before the Subcommittee on Irrigation and Reclamation of the Committee on Interior and Insular Affairs, United States Senate, Eighty-Sixth Congress, Second Session, on the Pacific Northwest (Bonneville)-California Intertie, June 15, 1960.

(e) Senate Committee on Interior and Insular Affairs, Resolution adopted July 21, 1960.

[3] Appendix B attached hereto.

the suspension is in effect now. This means that BPA power is not now available for export to California by the applicant in this case, or by any other private or public agency, and will not be available until the Congress has settled the important issues of public policy involved.

In the midst of this situation, and clearly for the political purpose of influencing that policy decision of the Congress, applicant has asked approval from this Commission for financing (and in an associated proceeding has asked approval for rate filings covering certain interchanges of power), involving a most singular construction project to be built jointly with Pacific Gas and Electric Company. This is to be a transmission line, approximately 110 miles long, from Klamath Falls, Oregon, to Round Mountain, California. It seems probable, though because of the absence of any hearing or record or meaningful investigation it is not certain, that the southern (PG&E) end of the line will not initially be connected to the PG&E Company Pit. No. 3 hydro project, thus hopefully avoiding the Commission's preliminary licensing authority, but will be thus connected after construction is completed. The line is planned to include pylons of extra carrying capacity, and 500 kv conductors and insulators. However, it will not initially, if ever, include 500 kv terminal facilities and will be placed in operation at 230 kv. The projected line is situated in such fashion as to constitute an almost mile-for-mile parallel and duplicate of a segment of the EHV line proposed by the Interior Department and now under consideration by the Congress.

This similarity of location and engineering design was highlighted in a news release by the Administrator of BPA on January 17, 1962[4] in response to inquiries of reporters. The Administrator, in guarded language, noted that applicant's proposed line was "consistent" with *engineering* recommendations of the Interior Department for its own proposed line, that the proposal "could provide an important link" in a full-length intertie, and that applicant had "expressed willingness to lease capacity in the intertie to Bonneville and other northwest utilities."

The Administrator pointedly did not endorse applicant's proposal, nor did he comment on the terms of lease offered to BPA by applicant. Instead he volunteered this significant comment:

> In view of our region's concern for protecting its power supply, BPA will make no commitment to export surplus Bonneville power outside the region until Congress has acted upon regional preference legislation. Announcement of the companies' plans makes it imperative that our entire region get behind the enactment of such legislation.

It is important that we take note of the significant differences between the two proposed lines. The Federal line is to be nearly 900 miles long, instead of 110; it is to have all the necessary terminal facilities for EHV operation between the Columbia River and the major California market areas; and it is to operate at extra high voltage from its inception.

The circumstances allow it to be said with complete fairness and accuracy that the main characteristics of applicant's proposed line, viewed in the light of the impending policy decisions in the Congress, are political. Its location was chosen for political effect. Its design and intended use have clear political overtones. The timing of its application before this Commission and the urgency with which immediate construction is advocated, reflect and reveal the forces of the political arena rather than the sober, deliberate business judgment with which utility executives ordinarily approach such an investment.

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[4] Appendix C attached hereto.

Because of the absence of an investigation, hearing, or adequate record in this proceeding, it is impossible, as I have already pointed out, to "find" that an isolated segment of line such as this, located in sparsely populated country with no heavy industry, connected at both ends to several hundred miles of lower-voltage conductors, and lacking any high-voltage terminals of its own, is "compatible with the public interest." The anomalies in its design and intended use are enough to give anyone immediate pause for reflection.

It is equally, and for the same reasons, impossible to reject the line out of hand as being uneconomic, imprudent or otherwise incompatible with the public interest. There simply is no record on which to base either approval or rejection. I therefore have not advocated rejection of the project in the present proceeding and I do not advocate rejection now.

On the other hand, it is comparatively easy to point out facts, probabilities and possibilities concerning this proposed line which at the very minimum require the most detailed investigation and sober consideration before giving it approval.

What I have advocated, and what I believe is clearly required by Section 204 (a), (b), and (c) of the Federal Power Act, is careful investigation and genuine opportunity for a hearing to determine whether the line is "compatible with the public interest" as alleged by the order. Failing this, we confront the public not merely with negligent failure of the Commission to secure the necessary information, but with the Commission's pointed and obdurate refusal to ask the necessary questions.

Let us consider the fragmentary facts available to us. All State and Federal authorities are agreed that a 230 kv line is justified and would be useful in the proposed location. The line as proposed would initially and for an undetermined period carry 230 kv but would be built (except for terminal facilities and connecting lines) to 500 kv capacity. The amount of over-building and over-investment has not been identified, but that it is a substantial amount cannot be denied. Clearly this over-building represents a complex gamble by PP&L and PG&E that (a) the building of a Federal or other publicly-owned intertie can and will be prevented; that (b) eventually the projected line will become a segment in a privately-owned Pacific Northwest-Pacific Southwest intertie; carrying (c) the Bonneville surplus load, in addition to company-generated surplus and other purchases. In any gamble involving three essential and interdependent elements such as those, the hazard factor increases geometrically.

If this three-ply gamble is successful, presumably the excess capacity of the segment under discussion here would at some future date become fully utilized and therefore economically justified. It follows that, whatever the eventual outcome, for an indeterminate period (during operation at 230 kv) the opposite would be true—the facilities could not be used to full capacity and would not be economically justified.

It also follows that if the gamble is unsuccessful, i.e., if a tie-line or system of tie-lines is built under Federal or other public ownership, it is probable if not certain that the excess capacity of the projected line will remain permanently, or for a very long period, unused and therefore permanently or semi-permanently unjustified from an economic viewpoint.[5]

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[5] Lest the foregoing reasoning be dismissed as theoretical, Appendices D and E are attached and should be studied carefully. Both are articles from *Electrical World*, a leading trade journal of the electric utility industry. Appendix D, published before the order was issued, illustrates how little was known of the purposes behind the application in this case, even within the industry itself. Appendix E, published after the order was issued and *received by me after this dissent was written* confirms the purposes and the strategy *and the gamble by applicant* already outlined in this dissent.

Here we enter an area in which the responsibilities of the Federal Power Commission are to me very clear and of major importance. Let me say at the outset that building excess capacity, in reasonable amounts for a future market that has been carefully assessed, is not only proper but commonplace in the utility industry, and on many occasions has had the support of this Commission, after proper investigation. But here we are not dealing with a solid and assured source of supply, and hence we cannot measure—in any case we have not measured—the market, its size, its rate of growth, or the degree to which it can predictably carry the costs of the proposed construction so as to rended it economically feasible. We have not done all these things, I repeat, because we are not dealing with, and applicant has not shown, and very probably cannot show, an assured source of power sufficient to load this proposed line.

It is persuasively clear from the applicant's filed rate documents and correspondence, as well as from the wording of contracts between applicant and PG&E,[6] that the proposed intertie is hopefully based on the seasonal Bonneville surplus (though applicant has access to smaller surplus supplies through other channels), and it may be presumed therefore that the Bonneville surplus is necessary in order to load and justify the proposed construction. Further, it is clear that the future contract which the applicant and its associate company hope some day to conclude with the Bonneville Power Administration is substantially the same as, if not identical with, the contract under negotiation between PG&E and BPA in 1959, prior to adoption of the Senate Interior Committee resolution in 1960 which effectively halted negotiations for such a contract. To say, therefore, that the source of power to load this line is nebulous and speculative is to put the matter very charitably indeed.

Brought together, all of the foregoing elements add up to a proposal which I do not believe can any longer be described as a "calculated business risk," in the words of Mr. Robert H. Gerdes, executive vice president of Pacific Gas & Electric Company, testifying in 1959.[7]

Mr. Gerdes so described PG&E's proposal to spend several million dollars on a tie-line in 1959, after admitting that under his proposed contract with BPA: "I will stipulate right now that the power can be curtailed at any time."[8]

If the proposal was a "calculated business risk" under those conditions in 1959, what does immediate construction of a tie-line look like now, with BPA under effective prohibition against even discussing a contract for export of power to California? Senators Kuchel and Jackson called the proposed construction a gamble in 1959, though Mr. Gerdes did not agree.[8] I believe it is indisputably a gamble now; a straight-out heads-or-tails political gamble depending entirely upon policy decisions still to be reached by the Congress. Yet the Commission was orally urged by the staff to approve the security issue in this proceeding at once because PP&L had construction crews in the field and wished to start construction of this line immediately in order to avoid penalties.

And Staff said, "Let there be haste;" and there was haste. The paraphrase may be slightly irreverent but it is entirely on point.[9]

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[6] Appendix F attached hereto.

[7] Hearings before the Subcommittee on Irrigation and Reclamation of the Committee on Interior and Insular Affairs, United States Senate, Eighty-Sixth Congress, First Session, on the Bonneville (Pacific Northwest)-California Intertie, April 8 and 9, 1959, page 165.

[8] Ibid., page 161.

[9] Judge Henry J. Friendly, of the United States Second Circuit, on February 13, 1962, in an Oliver Wendell Holmes lecture before the Harvard Law School adverted to the same subject in the following words: "In these large agencies a considerable amount of delegation is inevitable; definition of standards is required if the agency members are to be masters of the staff rather than the slaves of anonymous Neros, each fiddling his own tune."

Is there a possible basis in the public interest for allowing the construction of major excess capacity by a public utility to the extent proposed and under the conditions prevailing in this case? In justice to the rate-payers who will eventually defray the costs of construction under rates having the force of law, I cannot conceive of such a basis.

The argument has been made (and rejected by every regulatory commission worthy of the name) that regulatory authority is powerless to interfere with an adventure such as this because it lies within the inviolable prerogatives of management. It would be a waste of time and paper to cite all the cases which have held that, while there are some areas of management discretion which should not be invaded unless required by the public interest, every improper or improvident decision of management which threatens unduly to burden the rate-payer or otherwise to damage the public interest is subject to review and reversal. If it were otherwise, no regulatory law would ever have been enacted or could ever have been enforced.

Virtually every manager, and certainly very manager of a public utility in this country, who handles and spends other people's money is rightly subject to public scrutiny and control undr law, including the Federal Power Act, and I will not lengthen this dissent by laboring the point.

Another favorite thicket of the utility lawyer defending practices such as those under discussion here is the argument that no interference with an enterprise such as this one is proper because the impact of the actions complained of is not sufficient to bankrupt the company even if the worst consequences were to ensue, and the effect upon the individual rate-payer, while not exactly a happy one, would not be disastrous.

This begs the question and raises a smokescreen of sophistry into the bargain. There is a principle involved here, and a supremely important one. How can we condone practices on a limited scale which, if indulged on a larger scale, would unquestionably threaten the solvency of an entire utility system? Where's is the line of demarcation beyond which "tolerable" practices become intolerably dangerous?

Here too the respected regulatory agencies have refused to be led down the primrose path. There are industries, particularly in the extractive mineral field, wherein gambling is such an essential and customary part of their business practices that the courts have, without prejudice, likened them to a poker game. The electric utility industry has never been considered one of these. It should not become one under the aegis of the Federal Power Commission.

Section 204(a) provides that public utilities may not issue securities unless the Commission finds, among other things, that the purpose for which the proceeds will be spent is "compatible with the public interest." This provision has never been interpreted by the courts. Nevertheless some light as to the responsibility and burden which it imposes on the Commission and utility, respectively, can be gleaned from the court's interpretation of the similar but less stringent requirements of Section 203. The latter section prohibits electric utility mergers unless the Commission finds them to be "in the public interest." In *Pacific Power and Light Co., et al.* v. *Federal Power Commission*, 111 F. 2d 1014 at 1016, the court explained that the purpose of this provision is to insure

> against public disadvantages through a requirement of a showing that mergers . . . will not result in detriment to consumers or investors or to other legitimate national interests.

For this reason, it continued,

> the Commission properly *requires applicants to make a full disclosure of all material facts. The burden is on them* of showing affirmatively that the ac-

> quisition or merger is consistent with the public interest. The Commission must necessarily take an over-all view and in many cases it will . . . be called upon to weigh considerations pro and con. (Emphasis supplied.)

In the light of that pronouncement, I am unable to agree that the applicant here has made, or has been required to make, the showing clearly called for by the Act prior to granting the authorization requested. Section 204, as will be seen, is prohibitory in character; it permits authorization of securities "only if" the Commission has obtained information on which it can make the detailed findings that are conditions precedent to its action thereunder. In pertinent part, Section 204(a) of the Federal Power Act (16 USCA 824c) provides that:

> No public utility shall issue any security, . . . unless and until, and then only to the extent that, . . . the Commission by order authorizes such issue . . . The Commission shall make such order only if it finds that such issue . . . (a) is for some lawful object, within the corporate purposes of the applicant and compatible with the public interest, which is necessary or appropriate for or consistent with the proper performance by the applicant of service as a public utility and which will not impair its ability to perform that service, and (b) is reasonably necessary or appropriate for such purposes . . .

To determine these matters, the Act then at 204(b) says that the Commission may hold a hearing, and "may grant any application . . . in whole or in part, and with such modifications and upon such terms . . . as it may find it necessary or appropriate"—depending, that is, upon the extent to which it finds that the purpose of the issue has or has not been shown to meet the established standards. Any doubt as to the decisiveness and finality of the Commission's authority in this area is removed by Section 204(c). It states that "no public utility shall . . . apply any security or any proceeds thereof to any purpose not specified in the Commission's order . . . or otherwise in contravention of such order." In any event, if the Commission after investigation and hearing finds any matter inconclusive, premature or unsettled, it may retain continuing jurisdiction for the purpose of modifying its original order in the light of subsequent developments (Section 204(b).

The only reasonable construction of Section 204(a), as I read it, is that the language of clause (a) requires this Commission to obtain affirmative proof that the pupose for which the securities will be issued is not only lawful and within the corporate powers of the applicant, but that such purpose is also "compatible with the public interest" and appropriate to the proper performance of public utility service. It further appears that clause (b) requires the applicant to show, and the Commission to find, that the particular means proposed is either "reasonably necessary or appropriate." Faced with this latter choice, the majority "found" the proposed facilities to be neither "reasonably necessary" nor simply "appropriate," but "reasonably appropriate."

If this Commission properly is to exercise the responsibilities entrusted to it by the Congress under Section 204, it must examine into the purposes for which electric utility companies wish to issue securities. There is no other conclusion we can come to. And in determining the scope and extent of the efforts it must exert in discharging that responsibility, it is of little help to say that the Commission's investigation under Section 204 must be narrowly confined because the Commission does not have the power to issue or deny certificates of convenience and necessity for electric company construction. As that power was denied to this Commission in 1935 (see Senate Report No. 621, on S. 2796 in the 74th Congress, at p. 20), we obviously cannot disapprove or deny proposed construction on that ground. But that is no reason for suspending or confining

our inquiry, for the fact remains that this Commission can disapprove proposed utility construction under its power to approve or disapprove the purposes and projects for which utility securities to finance that construction will be issued.

Indeed, this has been done by state regulatory commissions armed with only security approval powers whenever, after an investigation and hearing, those commissions were satisfied that the purpose for which securities were to be issued was not "reasonably necessary" to carry out the stated purposes of the electric utility concerned.

Old Dominion Electric Cooperative, 86 PUR NS 129, is a case particularly in point—where a regulatory commission armed only with the power of approval or disapproval over security issues used that authority to prevent construction of generating and transmission facilities which the commission found not "reasonably necessary" for carrying out the company's utility responsibilities. The matter is discussed there in full.

Counsel for Old Dominion argue—

the Virginia Commission began—

> that the only question for the Commission to decide is whether or not $16,000,000 is needed to acquire the structures described in the application, . . . Under that interpretation of the statute the only issue before the Commission would be whether the amount of $16,000,000 is reasonably necessary. Since that amount obviously is necessary, it would lighten our labors if that were the correct interpretation of the statute.
>
> In our opinion that is not what the statute means. The . . . purposes of the law as well as its language show that the words "reasonably necessary" mean not merely that the amount of money sought through the issuance of securities must be necessary to acquire the proposed structures, but also that the proposed structures themselves must be reasonably necessary for the accomplishment of some purpose having to do with the obligations of the utility to the public and its ability to carry out those obligations with the greatest possible efficiency. * * * If the utility, by deciding to build a $16,000,000 plant automatically had the right to borrow $16,000,000, there would be no function for the State Corporation Commission to perform except solemnly to record the fact that $16,000,000 would be reasonably necessary to build a $16,000,000 plant. The general assembly, in passing the statute, could not, in our opinion, have intended that result, because it would appear to be very much better to have no statute at all than to have one that produced only that result. * * * Evidence that the general assembly meant for the Commission to consider the public interest and not merely the question of whether the amount of money sought was necessary to acquire the proposed plant is found in the following provisions of § 56–61:
>
> "The Commission may by its order grant permission for any such issuance or assumption in the amount or on the terms applied for, or in less amount, or on different terms, or not at all, and may include in its order such terms and conditions fairly relating to the matter of such issuance or assumption as it may deem reasonable or necessary."
>
> The quoted language gives the Commission authority it could not usefully exercise if its only function were to pass on the amount of money needed to acquire the plant and not on whether the plant itself was reasonably necessary to perform the public duties of the public utility.

The Supreme Court of Massachusetts interpreted the words "reasonably necessary," as used in a statute dealing with the issuance of securities by public utilities, in the same manner. Speaking in *Lowell Gas Light Company* v. *Depart-*

ment of Public Utilities, 62 PUR NS 238, at 243; 64 NE 2d 640, that Court said that:

> since the words "reasonably necessary" are not employed solely with reference to the amount of a proposed issue but refer also to the necessity of the issue itself, it follows inevitably that the Department must inquire whether the declared purpose of the proposed issue is in fact in the circumstances a reasonably necessary purpose. And having in mind that the function of the Department is the protection of public interests, we think that "reasonably necessary" means reasonably necessary for the accomplishment of some purpose having to do with the obligations of the company to the public and its ability to carry out those obligations with the greatest possible efficiency.

In this case, perhaps for the reasons spelled out in the Virginia and Massachusetts cases cited, the Commission avoided finding that the proposed construction was "reasonably necessary;" choosing to find instead that it was "reasonably appropriate."

I disagree. There are grave doubts, as I have shown, whether the proposed construction is or can be made "compatible with the public interest" in the existing circumstances. Until it passes that first and essential test *on the basis of findings of fact*, it is not helpful to talk about the proposed construction as being "reasonably appropriate." Such talk is, in fact, fuzzy, premature, and represents a conflict in terms.

The doubts concerning the projected construction are serious. They are genuine. They relate to the public interest which the applicant is required by law to serve and we are required by law to protect.

This order should be reconsidered by the Commission for the purpose of determining whether the projected construction is, in fact and in law, compatible with the public interest. If any portion of it is found wanting in this respect, restrictions should be placed upon the use of funds raised by this security issue for advancement of the specific project or projects involved, until such time as full campatibility with the public interest can be, and has been, factually demonstrated.

I repeat that, the extent we fail to do this, we confront the rate-paying public—and its elected and appointed representatives at both State and Federal levels—not merely with our failure to insist upon the necessary informaton but with our specific and repeated refusal to ask the necessary questions.

Whether such behavior is caused by legal obfuscation, confusion or timidity I am unable to say, but I heartly disagree with and dissent from it.

Appendix A

PACIFIC POWER & LIGHT COMPANY, DOCKET NO. E-7024

NOTICE OF APPLICATION

(March 1, 1962)

Take notice that on February 19, 1962, an application was filed with the Federal Power Commission pursuant to Section 204 of the Federal Power Act by Pacific Power & Light Company ("Applicant"), a corporation organized under the laws of the State of Maine and doing business in the States of Oregon, Wyoming, Washington, California, Montana and Idaho, with its principal business office at Portland, Oregon, seeking an order authorizing the issuance of $35,000,000, in principal amount of First Mortgage Bonds, Series due 1992. Applicant proposes to issue the aforesaid Bonds under its presently existing

Mortgage and Deed of Trust, dated July 1, 1947, to Guaranty Trust Company of New York (now Morgan Guaranty Trust Company of New York) and Oliver R. Brooks (Wesley L. Baker, successor), as Trustees, as heretofore supplemented by twelve supplemental indentures and as to be further supplemented by a Thirteenth Supplemental Indenture to be dated as of April 1, 1962. The Bonds, to be dated April 1, 1962, will be sold at competitive bidding and will bear interest at the rate per annum to be fixed by competitive bidding. Applicant states that the net proceeds of the issuance and sale of the Bonds and of not to exceed 696,695 additional shares of its Common Stock of the par value of $3.25 per share (proposed to be sold separately—Docket No. E–7025) will be applied to the payment of notes then outstanding (not expected to exceed $42,000,000 in principal amount) under a Credit Agreement dated as of August 15, 1961 and to the carrying forward of Applicant's construction program—estimated at $44,000,000 for 1962 and $56,000,000 for 1963.

Any person desiring to be heard or to make any protests with reference to said application should on or before the 21st day of March 1962, file with the Federal Power Commission, Washington 25, D.C., petitions or protests in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10). The application is on file and available for public inspection.

PACIFIC POWER & LIGHT COMPANY, DOCKET NO. E–7025

NOTICE OF APPLICATION

(March 1, 1962)

Take notice that on February 19, 1962, an application was filed with the Federal Power Commission pursuant to Section 204 of the Federal Power Act by Pacific Power & Light Company ("Applicant"), a corporation organized under the laws of the State of Maine and doing business in the States of Oregon, Wyoming, Washington, California, Montana and Idaho, with its principal business office at Portland, Oregon, seeking an order authorizing the issuance of not to exceed 696,695 shares of its Common Stock with a par value of $3.25 per share Applicant proposes to offer the aforesaid Common Stock initially on a pro rata basis to holders of record of Applicant's presently outstanding Common Stock on the rights offering record date, in the ratio of one share of additional Common Stock for each twenty shares then held. The price of the additional shares will be determined by Applicant's Board of Directors shortly before the proposed offering date, at an appropriate discount. Each common stockholder of record will receive a transferable subscription warrant expressed in terms of rights which will have a life of not less than twenty days. Where the number of rights evidence by a warrant is not evenly divisible by 20 or is less than 20, then the holder will be entitled to subscribe for one full share with the number of rights which exceeds a multiple of 20 or is less than 20. Applicant will not accept subscriptions for fractional shares. Any shares of the additional Common Stock not subscribed for by warrant holders pursuant to the aforesaid subscription offer will be sold by Applicant to underwriters at the same price at which the shares are to be sold to Applicant's stockholders. The underwriters' compensation for commitments to purchase any unsubscribed shares is to be fixed by competitive bidding. Applicant states that the net proceeds of the additional shares of Common Stock and of $35,000,000 in principal amount of First Mortgage Bonds, Series due 1992 (proposed to be sold separately—Docket No. E–7024) will be applied to the payment of notes then outstanding (not

expected to exceed $42,000,000 in principal amount) under a Credit Agreement dated as of August 15, 1961 and to the carrying forward of Applicant's construction program—estimated at $44,000,000 for 1962 and $56,000,000 for 1963.

Any person desiring to be heard or to make any protests with reference to said application should on or before the 21st day of March 1962, file with the Federal Power Commission, Washington 25, D.C., petitions or protests in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10). The application is on file and available for public inspection.

APPENDIX B

(The following resolution was adopted by the Senate Committee on Interior and Insular Affairs on July 21, 1960:)

PACIFIC NORTHWEST (BONNEVILLE)-CALIFORNIA INTERTIE

Whereas the Committee on Interior and Insular Affairs by resolution on May 19, 1959, requested the Secretary of the Interior to suspend all negotiations for the interconnection and the sale of surplus power from the Bonneville or Columbia River Basin system to California until a study and analysis of the feasibility and desirability of a high voltage interconnection for the disposal of surplus secondary energy between the Federal power systems of the Pacific Northwest and California; and

Whereas a report on the analysis requested was submitted to the committee under date of February 17, 1960; and the committee held public hearings May 5, 1960, and June 15, 1960, on the subject; and

Whereas the Governor of California, in cooperation with the Governors of Oregon and Washington, has requested further time for a study and analysis of a high voltage interconnection pending the completion of the report of consultants retained by the Governor of California in cooperation with the Governors of Oregon and Washington, and in consideration of legislation that would effectively protect the interests of the United States and the power consumers of the Pacific coast areas; and

Whereas the quantities of surplus energy which may be interchanged between the Pacific Northwest and California range from 4 billion kilowatt-hours in a dry year to 25 billion kilowatt-hours in a wet year; and

Whereas the committee has heard testimony asserting very substantial benefits accruing from the construction of a high-voltage interconnection between the Pacific Northwest and California and indicating that further studies are required to make a full disclosure of the potentialities of the proposed intertie; and

Whereas the committee finds that the public interest in the interconnection and transfer of power or energy within the Pacific coast areas may require legislation to insure protection of the Federal power and multiple-purpose projects in the systems; and

Whereas a completion of the independent study and analysis of the proposals is essential before any commitment is made on behalf of the United States with respect to the transfer of power or energy from one area to the other of the Pacific Coast States; Therefore be it

Resolved, That the Committee on Interior and Insular Affairs requests the Secretary of the Interior to continue to suspend negotiations looking to the sale and transfer of surplus power or energy from the Pacific Northwest to California, pending the completion of the survey and analysis by the consultants retained by the Governors of the Pacific Coast States; the submission of their

report to the committee; and the consideration of legislation that will protect the interests of the United States and the power consumers concerned; be it further

Resolved, That the committee requests the Secretary to submit to the committee for consideration at the next session of the Congress a draft of proposed legislation designed to guarantee to consumers in the Pacific Northwest States first call on power generated by Federal agencies in that region, as requested by the Governors of the Pacific Coast States; be it further.

Resolved, That the Secretary advise the committee of his action with respect to compliance with the request in this resolution.

Approved by the Committee on Interior and Insular Affairs on June 21, 1960.

JAMES E. MURRAY,
Chairman.

APPENDIX C

COMMENT BY BONNEVILLE POWER ADMINISTRATOR CHARLES F. LUCE ON THE PROPOSED NEW INTERCONNECTION BETWEEN PACIFIC POWER & LIGHT COMPANY AND PACIFIC GAS AND ELECTRIC COMPANY

The plans of Pacific Power and Light Company and Pacific Gas and Electric Company for a 110-mile 500-kv California intertie are consistent with engineering recommendations of our Task Force report on a Pacific Northwest-Pacific Southwest intertie.

The companies' proposal could provide an important link in a full length extra high-voltage common carrier intertie between the generating plants of the Northwest and California. Pacific Power has expressed willingness to lease capacity in the intertie to Bonneville and other northwest utilities.

In view of our region's concern for protecting its power supply, BPA will make no commitment to export surplus Bonneville power outside the region until Congress has acted upon regional preference legislation. Announcement of the companies' plans makes it imperative that our entire region get behind the enactment of such legislation.

APPENDIX D

A 110-mile line built for 500-kv operation will be the third transmission intertie between Pacific Gas & Electric Co. and Pacific Power and Light Co. Each company will build half the line, which will run from Klamath Falls, Oreg., to Round Mountain in Shasta County, Calif. Cost is estimated at $10 million.

Construction will begin as soon as possible, and completion is expected by the fall of 1963. Initial operation will be at 230 kv, and conversion to 500 kv will be made when joint studies of load and operating requirements indicate the increase to EHV should be made.

The line closely parallels a line proposed by PG&E in 1960, which was not built after Senator Murray's (D–Mont.) Interior and Insular Affairs Committee indicated that the Committee felt it would conflict with larger proposals also being studied at the time. That proposal, however, was contingent on sale of surplus power by Bonneville Power Administration to PG&E, while no such agreement is included in the present line.

Capacity of the new line was not disclosed, but the capacity of the 230-kv line proposed in 1960 was 200 Mw. At present there are two interconnections between PG&E and PP&L—the 110-kv Cottonwood line and the 69-kv Stillwater

line, which run from separate PG&E switching stations in Shasta County to PP&L's transmission system in Siskiyou County, Oreg.

In announcing the line PG&E's president Norman R. Sutherland said, "We have had interconnections for many years with the utility company to the north of us, as well as with the companies bordering our service territory to the East and to the South. Such interconnections have been augmented and expanded as needed. This new line will assure transmission capability for the additional power that will become available as we and the other companies expand our capacities in the years ahead."

A paragraph in the contract between the two companies reads: "We shall continue to study jointly the economic feasibility, in the light of developing circumstances, of converting the line to operation at not less than 500 kv and also of extending it in a northerly and southerly direction to provide an EHV intertie between the Pacific Northwest and California. It is understood that we will convert the line to operation at not less than 500 kv and extend it in both directions at such time as we jointly determine that such actions are economically justified."

Charles F. Luce, Bonneville Power Administrator and chairman of the special task force that proposed an EHV tie linking California and the Northwest (EW, Dec. 25, 1961, p. 34), called the PG&E–PP&L proposal "consistent with engineering recommendations of our task force report."

Luce also noted, "The companies' proposal could provide an important link in a full-length EHV common carrier intertie between the generating plants of the Northwest and California. Pacific Power and Light has expressed willingness to lease capacity in the intertie to BPA and other Pacific Northwest utilities."

Luce's statement emphasized that BPA would "make no commitment to export surplus power outside the region until Congress has acted upon regional preference legislation." He said that the announcement "makes it imperative that our entire region get behind the enactment of such legislation."

(From *Electrical World*, January 29, 1962, pp. 55–56.)

Appendix E

FOUR CALIFORNIA UTILITIES MAKE EHV TIE OFFER

Principal state investor-owned companies make proposal to transport Northwest power into Southern California

California's four principal investor-owned utilities have offered to construct an extra-high-voltage transmission line to carry Northwest power to southern California.

The offer is in effect a competing proposal to the Interior Department's task force proposal for a 750-kv, dc line between Bonneville Power Administration and California (EW, Dec. 25, 1961, p. 34).

The joint proposal by the four utilities—Pacific Gas & Electric Co., Southern California Edison Co., California Electric Power Co., and San Diego Gas & Electric Co.—was made contingent upon Northwest power being available and on terms that will make construction of the line economically feasible. These four utilities recently formed the California Power Pool (EW, Dec. 25, 1961, p. 34).

The offer, referred to in PG&E's just-issued 1961 annual report, was believed to have been made during a meeting with BPA chief Charles Luce and other officials several weeks ago.

To be constructed in stages

The report goes on to say: "This line will be constructed in stages as needed and existing transmission capacity of the California companies will be used to the maximum extent to avoid uneconomic duplication of facilities. In view of the transmission lines now existing and to be constructed by the California companies, there is no need whatever for the federal government to spend vast sums of taxpayer's money to construct the transmission facilities recommended by the (Interior) task force. The lines to be built by the California companies will be at no cost to taxpayers and, furthermore, will be productive of substantial tax revenue."

The proposed line (of not less than 500 kv) would extend south from PG&E's Round Mountain Substation in the Shasta area. North from Round Mountain will be the previously announced $11 million, 103-mile, 500-kv intertie with PP&L's 230-kv system at Klamath Falls, Oreg. (EW, Jan. 29, p. 55).

No mention is made in the PG&E report of a further extension north from Klamath Falls to The Dalles or some other point in the BPA system. Presumably, some sort of extension would have to be built if the California Pool offer is accepted.

Meanwhile, the California Pool operation is moving ahead. The first step occurred last December with the closing of an existing 220-kv tie between PG&E's Midway Substation and SoCalEd's Magunden Substation, both near Bakersfield. The 250-Mw tie, which will be used for emergencies, has been open for some years. Previously, PG&E used it to buy surplus power from SoCalEd when that company was taking power from Hoover Dam.

The four pool members are presently working on details of further interconnections and other arrangements to permit full operation of the pool.

Finally, details have been released on the 500-kv Round Mountain-Klamath Falls line. Some 600 latticed steel guyed H-frame structures will be used to carry the ACSR cable. Maximum design voltage will be 550 kv. The line will be completed in the fall of 1963 and will be operated first at 230 kv.

(From *Electrical World*, April 2, 1962, p. 26.)

APPENDIX F

PACIFIC GAS AND ELECTRIC CO.,
245 Market St., San Francisco 6, Calif.
January 5, 1962.

N. R. Sutherland, president.
PACIFIC POWER & LIGHT CO.,
Public Service Bldg.,
Portland 4, Oreg.

GENTLEMEN: This letter states our agreement to augment our existing electric interconnection facilities by the construction of a new large capacity transmission line to provide for the sale and exchange of energy between our companies and for the parallel operation of our systems, and to provide facilities and arrangements that make possible the sale and exchange of energy between other electric systems in the Pacific Northwest and PG&E, either directly or indirectly through PP&L.

We agree to continue to maintain our respective portions of our existing interconnecting transmission lines. These lines, which connect our electric systems at two points, both located at Delta in Shasta County, are the "Cottonwood Line", a 110-kv electric transmission line running from PG&E's Cottonwood Substation via Delta to PP&L's COPCO No. 2 Power House in Siskiyou County,

and the "Stillwater Line", a 60-kv electric transmission line running from PG&E's Stillwater Substation "B" via Delta to PP&L's COPCO No. 2 Power House in Siskyou County.

In addition, we agree to construct, operate and maintain a new transmission line running from Klamath Falls to Round Mountain, with the point of interconnection on or in the immediate vicinity of the township boundary line between Townships 42 N and 43 N in Range 1 E, MDB&M. PP&L will construct, own, and operate the northern section of the line, with terminal facilities at Klamath Falls, and PG&E will construct, own, and operate the southern section, with terminal facilities at Round Mountain and also, if it wishes, at Pit 3. The line shall be capable of operating at not less than 500 kv, and shall be designed and constructed in accordance with specifications acceptable to both parties. However, the line will be operated initially at 230 kv, and accordingly the terminal facilities shall be constructed for initial operation at that voltage. The construction of the line and terminal facilities shall be commenced promptly after the execution of this agreement, and shall be completed as soon as practicable.

We shall continue to study jointly the economic feasibility, in the light of developing circumstances, of converting the line to operation at not less than 500 kv and also of extending it in a northerly and southerly direction to provide an extra high voltage intertie between the Pacific Northwest and California. It is understood that we will convert the line to operation at not less than 500 kv and extend it in both directions at such time as we jointly determine that such actions are economically justified.

After supplying customers off of the Cottonwood and Stillwater Lines, the primary use of the three interconnecting lines shall be for firm service, exchange service (including emergency service) and sales of surplus energy between PP&L and PG&E. It is contemplated that PP&L may have transmission capacity in its system that will not be required for purposes deemed necessary by PP&L. PP&L intends to make such excess transmission capacity, along with any excess capacity in the three interconnecting lines after serving their primary use, available for service between Bonneville Power Administration and utility companies in the Pacific Northwest and PG&E. In such case PP&L will make a reasonable charge for transmitting the energy of any other company or agency over its system, the exact amount of the charge to be as agreed upon between PP&L and the owner of the energy.

PG&E and PP&L will plan and operate their systems so that the flow of reactive power will not adversely affect the system of the other, and they shall operate, or provide for others to operate, adequate tie line and frequency control equipment so as to minimize the power swings over the lines and to contribute a proportionate share of the total interconnected system frequency regulation. In addition, an operating committee consisting of an equal number of representatives from each company shall meet from time to time to agree upon methods of operation and related matters in order to achieve the purposes of this agreement, and such matters shall include, but not be limited to, reactive power, voltage regulation, tie line control settings, clock corrections, deviations from energy delivery schedules, emergency operations, estimates of deliveries during meter outages, and scheduling arrangements.

From time to time PP&L may desire to purchase energy from PG&E. PG&E agrees to sell PP&L energy provided that PG&E has surplus energy and the parties have mutually agreed as to the price to be paid, the period to be covered and the time of day deliveries are to be made.

The power sale agreement dated July 14, 1952, as heretofore amended and supplemented, between PG&E and The California Oregon Power Company and to which PP&L is the successor, is hereby in its entirely cancelled effective February 1, 1962. Appropriate notice shall be given to the Federal Power Commission immediately upon the execution hereof and the necessary schedules filed with the Commission in accordance with the terms of this agreement.

Service will commence under this agreement and in accordance with the attached rate schedules on February 1, 1962, and the agreement will remain in effect until February 1, 1972, and from year to year thereafter, terminable on one year's written notice given by either one of us at any time after January 31, 1971.

If this letter and the attached schedules correctly state our agreement, please sign and return one of the enclosed copies hereof.

Yours very truly,

PACIFIC GAS AND ELECTRIC COMPANY

By ----------

We agree:

PACIFIC POWER & LIGHT COMPANY,

By D. R. MCCLUNG.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. G-10000

ORDER FIXING HEARING ON PETITION TO MODIFY ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 28, 1962)

On February 16, 1962, Transcontinental Pipe Line Corporation (Transco) filed a petition, as amended February 19, 1962, requesting that the Commission modify its order and Opinion No. 302, issued March 1, 1957, in the above-entitled proceeding, so as to effect a reallocation of gas for a temporary period and to permit Transco to render certain services during such temporary period, all as hereinafter described.

By Opinion No. 302 the Commission authorized Transco, *inter alia*, to undertake new service to North Carolina Natural Gas Corporation (North Carolina Natural)[1] pursuant to a firm allocation granted therein of 39,780 Mcf per day. North Carolina Natural proposed to use this allocation to serve the natural gas requirements of Tidewater Natural Gas Company (Tidewater) and of other customers within the State of North Carolina. Service by Transco to North Carolina Natural commenced on April 14, 1959. The petition seeks to effect a reallocation of gas for a period of three years so as to permit Transco to render firm service during such temporary period directly to Tidewater.

Tidewater, one of North Carolina Natural's major customers owns and operates five gas distribution systems or divisions located in Fayetteville, Kinston, New Bern, Washington and Wilmington, North Carolina, respectively. The petition alleges that slower than expected market developments have resulted in a poor

[1] North Carolina Natural, a customer of Transco, is engaged in the sale of gas throughout the State of North Carolina. North Carolina Natural is not subject to the Commission's jurisdiction.

earnings position of Tidewater. It appears that Tidewater is still in the developmental stage in changing its operations from manufactured gas to natural gas.

The relief sought by Tidewater, which Transco proposes herein to provide, will require that for a three-year period beginning April 1, 1962, portions of the present allocation of North Carolina Natural be transferred by the Commission to and divided among the five Divisions of Tidewater, and be billed under Transco's Rate Schedule OG–2. The allocations to be transferred, in total volumes of 8,590 Mcf for the period April 1, 1962, to January 1, 1963, and 10,323 Mcf for the period January 1, 1963, to April 1, 1965, are based upon Tidewater's estimates of its requirements from Transco by Divisions for the three-year period, as follows:

Tidewater division	Apr. 1, 1962 to Jan. 1, 1963	Jan. 1, 1963 to Apr. 1, 1965
Fayetteville	2,690	3,400
Kinston	1,050	1,200
New Bern	1,050	1,200
Washington	625	700
Wilmington	3,175	3,823
Total	8,590	10,323

During the time these temporary reallocations are effective, North Carolina Natural will surrender equivalent volumes under its CD–2 service agreement with Transco. The Transco-North Carolina Natural CD–2 service agreement will, consequently, provide for the following maximum daily quantities during the periods shown:

Period	Maximum daily quantity		Reduction
	Present agreement	Proposed agreement	
To November 1, 1962	28,000	19,410	(8,590)
November 1, 1962 to January 1, 1963	36,500	27,910	(8,590)
January 1, 1963 to November 1, 1963	36,500	26,177	(10,323)
November 1, 1963 to April 1, 1965	39,780	29,457	(10,323)
April 1, 1965 and thereafter	39,780	39,780	0

Tidewater will purchase its base load requirements from Transco. If Tidewater requires more natural gas on any day than its allocation from Transco would provide, it will look to North Carolina Natural for such additional volumes.

North Carolina Natural has agreed to release gas to Tidewater and thereby to forego sales to Tidewater represented by such released volumes, *provided* Transco is agreeable to selling to North Carolina Natural for the three-year period involved, at a rate equal to the Commodity Charge under Transco's Rate Schedule CD–2, a daily volume of gas equal to the difference between the total quantity allocated to Tidewater hereunder and any lesser total quantity purchased and received by Tidewater.

All volumes of gas purchased by Tidewater from Transco will be delivered by Transco and received for the account of Tidewater at Transco's existing point of delivery to North Carolina Natural, from which point such purchased gas will be transported and delivered to the respective Divisions by North Carolina Natural.

The Commission finds:

It is necessary in the public interest that the issues raised by the petition of Transco be explored on a formal record and that appropriate findings be made by a Presiding Examiner of the Commission.

The Commission orders:

A hearing on the issues raised by the petition of Transco to modify the Commission's order in Opinion No. 302 be convened on April 16, 1962, before a Presiding Examiner of the Federal Power Commission at 441 G St. NW., Washington 25, D.C., at 10:00 a.m., e.s.t.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

UNION TEXAS NATURAL GAS CORPORATION (OPERATOR) ET AL., DOCKET NO. RI62-258; UNION TEXAS NATURAL GAS CORPORATION, RI62-259

ORDER DENYING MOTION TO TERMINATE PROCEEDINGS

(Issued March 28, 1962)

On February 16, 1962, Union Texas Natural Gas Corporation (Union) filed a motion wherein it requested that the Commission terminate the above-docketed proceedings and permit the suspended increased rates involved therein to become effective immediately without obligation to refund. The subject increase in rates, from 11 cents to 12 cents per Mcf at 14.65 psia, pertain to Union's jurisdictional sales of natural gas to Arkansas Louisiana Gas Company (Arkansas Louisiana) from the Chickasha Field, Grady County, Oklahoma.

In support of its motion, Union states (1) that, prior to its filing the proposed increased rates on November 24, 1961, four other independent producers' substantially similar sales to Arkansas Louisiana were permitted to become effective without suspension; (2) that since the issuance of the Second Amendment to the Policy Statement No. 61-1, the Commission has reaffirmed its policy of permitting adjustments in price based upon the elimination of favored-nation and other similar type clauses with respect to sales outside of Texas District Nos. 2, 3, 4 and 6, citing: *Bert Fields, et al.*, 25 FPC 983; and (3) that the suspension of its increased rates for sales of gas to Arkansas Louisiana in the same area is purportedly discriminatory and inconsistant with the Commission's Statement of General Policy No. 61-1, as amended.

As cited above, the Commission had permitted proposed increased rates to become effective without obligation to refund at the level requested by Union in the Oklahoma "Other Area." However, we do not consider that prior decisions concerned with an increased rate in the same producing area precludes our analysis of all pertinent factors pertaining to the instant proceedings and the continued re-examination of pertinent policies affecting the public interest, particularly since the increased rates involved are in excess of the area price levels as announced in the Statement of General Policy No. 61-1, as amended. Cf. *F.C.C.* v. *Pottsville Broadcasting Co.* 309 U.S. 134, 145; *Panhandle Eastern Pipe Line Co.* v. *FPC*, 236 2d 289.

The Commission finds:

Accordingly, we conclude in this instance that Union's motion to terminate the proceedings in Docket Nos. RI62-258 and RI62-259 should be denied.

The Commission orders:

Union's motion filed in these proceedings on February 16, 1962, is hereby denied.

Commissioner O'Connor *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

NEW YORK STATE NATURAL GAS CORPORATION, DOCKET NO. CP62-25

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 29, 1962)

On January 15, 1962, an amended application, which was further amended on January 18, 1962 and on March 7, 1962, was filed by New York State Natural Gas Corporation (New York Natural) superseding its original application filed July 28, 1961, as amended and supplemented October 19, 1961, requesting authorization to construct and operate a 12-inch diameter pipeline extending approximately 23.2 miles from a terminus of its pipeline system near Auburn in Cayuga County, New York, to its existing regulator at the Phelps Connection in Ontario County, New York, and a measuring station near Phelps, in order to meet increased requirements in the western portion of the Auburn-Geneva market area served by New York State Electric and Gas Corporation (New York Electric), all as more fully set forth in the application, as amended and supplemented.

Further, Applicant has an isolated connection at Phelps with the system of Tennessee Gas Transmission Company (Tennessee) for emergency service directly to New York Electric. Upon completion of the proposed 12-inch extension (called the "Phelps" Line) Applicant's main pipeline system will be interconnected with the pipeline system of Tennessee at the Phelps Connection, thus providing a valuable connection in case of emergency on applicant's main pipeline system.

Based on annual volumes estimated to be delivered through the proposed line, Applicant shows the following incremental return on its proposed investment:

	1962	1963	1964
Estimated volumes (Mcf)	2,115,000	2,292,000	2,553,000
Total revenues (at 53.15 cents per Mcf)	$1,124,123	$1,218,198	$1,356,920
Total expenses including cost of gas at 41.3 cents per Mcf	1,032,851	1,116,841	1,240,692
Net income	$91,272	$101,357	$116,228
Return, percent	8.8	9.8	11.2

The estimated cost of such facilities is $1,038,447, to be financed from funds on hand. Applicant states that it will not include the proposed investment in its rate base for any period prior to November, 1964. Applicant also states, at page 2 of its amendment and supplement of March 7, 1962, that,

> New York Natural will not, in any proceeding fixing rates for any period, include or claim in its cost of service applicable to its existing Rate Zones 1 and 2, any costs for the Phelps line covered by this application. New York Natural believes that, in any proper allocation of costs to its existing

Rate Zones, no Phelps line costs should be assigned to its existing Rate Zones 1 and 2, for among other reasons, the said line is to be located and operated within its Rate Zone 3.

On March 8, 1962, in reliance on the above quotation, the North Penn Gas Company (North Penn), a customer of New York Natural in Rate Zones 1 and 2, filed a notice of withdrawal of its petition to intervene, filed on January 5, 1962[1] and amended on February 2, 1962.[2] We do not at this time pass judgment on the proper allocation method to be employed in a subsequent rate proceeding. The Commission therefore is not bound by the statement of New York Natural, above quoted.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 22, 1962, respecting the matters involved in and the issues presented by the application, herein, as supplemented and amended. No protest to the granting of the application has been received. All customers of Applicant have notified the Secretary by letter or telegram that they do not object to the omission of the intermediate decision procedure nor to the Commission rendering a decision pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure. New York Electric intervened in favor of the Applicant. Staff Counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, New York State Natural Gas Corporation, a New York Corporation having its principal place of business in Pittsburgh, Pennsylvania, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 27, 1942, in Docket No. G-312 (3 FPC 844).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented and amended, in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(6) The time within which the construction of the facilities hereinafter authorized should be completed and said facilites placed in actual operation should be fixed at 8 months from the date on which this order issues.

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[1] Answer in opposition filed by Applicant on January 22, 1962. By letter of the Secretary dated January 16, 1962, Applicant was granted an extension to and including January 22, 1962, within which to answer the petition of North Penn.

[2] Answer in opposition filed by Applicant on February 19, 1962. By letter of the Secretary dated February 13, 1962, Applicant was granted an extension to and including February 19, 1962, within which to answer the amended petition of North Penn.

(7) The statement of Applicant that all costs attributable to the facilities hereinbefore described should be allocated to its existing Rate Zone 3 is not a matter appropriate for determination at this time.

(8) The certificate issued hereinafter should be conditioned upon Applicants not including the proposed investment in its rate based prior to November 1964.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant of Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, New York State Natural Gas Corporation, to construct and operate the proposed facilities, as hereinbefore described, all as more fully described in the application, as supplemented and amended, in this proceeding, upon the terms and conditions of this order.

(B) Applicant shall not include any of the proposed investment in its rate base prior to November 1964.

(C) Nothing herein should be construed as approval of Applicants statement that all costs attributable to the facilities hereinbefore described should be allocated to its existing Rate Zone 3.

(D) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(E) The facilities authorized by paragraph (A) above shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 8 months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CITIES SERVICE GAS COMPANY, *ET AL.*, DOCKET NO. CP61–263, *ET AL.*; ARKANSAS LOUISIANA GAS COMPANY, *ET AL.*, DOCKET NO. CP62–40, *ET AL.*; OKLAHOMA NATURAL GAS GATHERING CORPORATION, *ET AL.*, DOCKET NO. CI61–1408, *ET AL.*[1]

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND ACCEPTING RELATED FPC GAS RATE FILING[1]

(Issued March 30, 1962)

On April 10, 1961, Cities Service Gas Company (Cities Service) filed in Docket No. CP61–263 an application pursuant to Section 7(c) of the Natural Gas Act (Act) for a certificate of public convenience and necessity authorizing the construction and operation of approximately 23 miles of 16-inch pipeline from a point on Cities Service's existing Oklahoma City 20-inch main transmission pipeline in Noble County, Oklahoma, westerly to a point in Garfield County, Oklahoma, where it will connect with the existing 12-inch pipeline of Oklahoma Natural Gas Gathering Corporation (Gathering) from whom Cities Service pro-

[1] Additional applicants omitted in printing.

poses to purchase and take delivery of not to exceed 40,000 Mcf of natural gas per day, all as more fully set forth in the aforesaid application in Docket No. CP61–263.

Cities Service's estimated cost for the proposed project is $850,000, which will be financed from treasury cash.

On March 28, 1961, Oklahoma Natural Gas Gathering Corporation filed in Docket No. CI61–1408 an application pursuant to Section 7(c) of the Act for a certificate of public convenience and necessity authorizing the aforementioned sale to Cities Service of natural gas which Gathering proposes to purchase in the Ringwood Field, Major County, Oklahoma, as hereinafter described and as more fully described in Gathering's application in said Docket No. CI61–1408. The subject sale will be made pursuant to a gas sales contract between Gathering and Cities Service dated March 23, 1961, as amended by letter filed January 16, 1962, at an initial price of 17.5 cents per Mcf at 14.65 psia, the volume limited to a maximum of 40,000 Mcf per day.

Gathering proposes to purchase natural gas jointly with Warren Petroleum Corporation (Warren) from certain producers thereof in the Ringwood Field as set forth in the twenty-seven producer applications enumerated hereinafter, pursuant to individual contracts, at 11.0 cents per Mcf at 14.65 psia. Warren will take liquid products only from the subject gas and will have no title to the residue gas after processing at a gasoline plant in the Ringwood Field. Gathering will gather the gas, transport it to the processing plant where Warren will extract the liquids, then Gathering will deliver it to Cities Service in Garfield County as aforesaid.

The applications under which producers in the Ringwood Field seek authorization to sell natural gas to Gathering and Warren pursuant to gas sales contracts filed concurrently as initial rate schedules for the respective proposed services, are designated as follows: CP62–40, CI61–1545, CI61–1553, CI61–1557, CI61–1561, CI61–1569, CI61–1587, CI61–1590, CI61–1599, CI61–1639, CI61–1654, CI61–1655, CI61–1664, CI61–1667, CI61–1678, CI61–1693, CI61–1711, CI61–1712 CI61–1738, CI61–1746, CI61–1747, CI61–1785, CI61–1792, CI61–1813, CI62–569, CI62–570 and CI62–938.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 22, 1962, respecting the matters involved in and the issues presented by the applications herein. No petitions to intervene or protests to the granting of the respective applications have been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Cities Service Gas Company, a Delaware corporation having its principal place of business in Oklahoma City, Oklahoma, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of December 28, 1943, in Docket No. G–298 (4 FPC 471).

(2) Applicant, Arkansas Louisiana Gas Company, a Delaware corporation having its principal place of business in Shreveport, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of January 26, 1943, in Docket No. G–252 (3 FPC 910).

(3) Each Applicant in the remaining dockets enumerated in the caption of this order is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission, or will be engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption,

subject to the jurisdiction of the Commission, and will, therefore, be a "natural-gas company" within the meaning of said Act upon commencement of the service under the respective authorizations granted hereinafter.

(4) The facilities to be constructed by Cities Service, as hereinbefore described and as more fully described in the application in Docket No. CP61–263, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Cities Service are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) The construction and operation of the facilities proposed by Cities Service in Docket No. CP61–263 are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(6) Public convenience and necessity require that the certificate hereinafter issued to Cities Service and the rights granted thereunder be conditioned upon Cities Service's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(7) The sales of natural gas by the respective Applicants as described in the respective applications, other than Docket No. CP61–263, enumerated in the caption of this order, will be made in interstate commerce, subject to the jurisdiction of the Commission, and such sales by the respective Applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(8) The sales of natural gas by the aforesaid Applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(9) The respective Applicants in this consolidated proceeding are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(10) The respective related rate schedules and supplements thereto should be accepted as hereinafter ordered and conditioned.

(11) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Cities Service Gas Company, to construct and operate the facilities hereinbefore described, as more fully described in the application in Docket No. CP61–263, upon the terms and conditions of this order.

(B) Certificates of public convenience and necessity be and the same are hereby issued, upon the terms and conditions of this order, authorizing the sales by the respective Applicants, other than Cities Service Gas Company, in this consolidated proceeding, of natural gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary for such sales, all as hereinbefore

described and as more fully described in the respective applications, amendments, supplements and exhibits aforesaid in this proceeding.

(C) The certificate issued to Cities Service Gas Company by paragraph (A) above and the rights granted thereunder are hereby conditioned upon Cities Service's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(D) The time within which the facilities authorized in paragraph (A) above shall be completed and said facilities placed in actual operation is hereby fixed at six months from the date on which this order issues.

(E) The certificates issued to the respective Applicants by paragraph (B) above are not transferable and shall be effective only so long as said Applicants continue the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations and orders of the Commission.

(F) The grant of the certificates issued by paragraph (B) above shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or of Part 154 or Part 157 of the Commission's Regulations thereunder, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the respective Applicants. Further, our action in this proceeding shall not foreclose nor prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contracts herein involved. Nor shall the grant of the certificates aforesaid for service to the particular customers involved imply approval of all of the terms of the respective contracts, particularly as to the cessation of service upon the termination of said contracts as provided by Section 7(b) of the Natural Gas Act. Nor shall the grant of the certificates aforesaid be construed to preclude the imposition of any sanctions pursuant to the provisions of the Natural Gas Act for the unauthorized commencement of any sales of natural gas subject to said certificates.

(G) The authorization granted to Oklahoma Natural Gas Gathering Corporation in Docket No. CI61–1408 by paragraph (B) above is hereby conditioned upon the use of a total initial price of 17.5 cents per Mcf at 14.65 psia, as agreed to by Gathering.

(H) Oklahoma Natural Gas Gathering Corporation is hereby directed to make all future filings pursuant to the Commission's regulations governing pipeline company filings.

(I) The authorization granted to Tidewater Oil Company in Docket No. CI61–1599 by paragraph (B) above is hereby conditioned upon the filing by Tidewater of an acceptable related rate schedule for the proposed service as heretofore requested.

(J) The related rate schedules listed below are accepted for filing to be effective on the date of initial delivery, excepting the filing of Arkansas Louisiana Gas Company related to Docket No. CP62–40 which shall become effective upon the date of issuance of this order. Such acceptance for filing shall not be construed as constituting approval by this Commission of any service, rate, charge, classification, nor any rule, regulation or practice affecting such service or rate; nor shall this order be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Applicants involved. Further, in the event that any

document comprising the listed rate schedules was executed on or after April 3, 1961, and contains provisions, either therein or by adoption of the terms and provisions of other agreements, for a change in rate other than those permitted by Section 154.93 of the Commission's Regulations under the Natural Gas Act, such rate change provisions shall be inoperative and of no effect at law and any tendered rate change under such provisions will be rejected.

Docket No.	Rate schedule designation	Description of document	Date of document
CP62-40	Arkansas Louisiana Gas Company FPC Gas Rate Schedule XFS-20.	Basic Contract	June 28, 1961.
CI61-1408	Oklahoma Natural Gas Gathering Corporation FPC Gas Rate Schedule No. 1.	Basic Contract	Mar. 23, 1961.
CI61-1545	Colorado Oil and Gas Corporation (Operator), *et al.* FPC Gas Rate Schedule No. 50.	Basic Contract	Mar. 28, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1553	Forrest H. Lindsay d.b.a. National Associated Petroleum Company FPC Gas Rate Schedule No. 3.	Basic Contract	Feb. 7, 1961.
	Supplement No. 1 to above	Assignment	Mar. 21, 1961.
	Supplement No. 2 to above	Assignment	Mar. 21, 1961.
	Supplement No. 3 to above	Assignment	Mar. 21, 1961.
CI61-1557	Livingston Oil Company (Operator) FPC Gas Rate Schedule No. 1.	Basic Contract	Dec. 21, 1960.
	Supplement No. 1 to above	Basic Contract	Dec. 21, 1960.
		Amendatory Agreement	May 23, 1961.
	Supplement No. 2 to above	Letter Agreement	May 23, 1961.
CI61-1561	D. H. Rowland FPC Gas Rate Schedule No. 1	Basic Contract	Feb. 3, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1569	Bolsa Chica Oil Corporation FPC Gas Rate Schedule No. 1.	Basic Contract	Feb. 6, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1587	Roger H. Davis FPC Gas Rate Schedule No. 1	Basic Contract	Feb. 2, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1590	Indeco Corporation FPC Gas Rate Schedule No. 1.	Basic Contract	Feb. 21, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1639	Oklahoma Natural Gas Company (Operator), *et al.* FPC Gas Rate Schedule No. 15.	Basic Contract	Feb. 24, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1654	Emby Kaye, *et al.* FPC Gas Rate Schedule No. 4.	Basic Contract	Feb. 21, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1655	Union Texas Petroleum, *et al.*, a Division of Allied Chemical Corporation FPC Gas Rate Schedule No. 61.	Redesignation of Basic Contract of predecessor Union Texas Natural Gas Corporation, *et al.* FPC Gas Rate Schedule No. 61.	Mar. 29, 1961.
	Supplement No. 1 to above	Assignment	Apr. 1, 1961.
CI61-1664	Cities Service Petroleum Company FPC Gas Rate Schedule No. 150.	Basic Contract	Feb. 22, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1667	K. C. Hawkinson, *et al.* FPC Gas Rate Schedule No. 1.	Ratification	Mar. 1, 1961.
	Supplement No. 1 to above	Basic Contract	Feb. 15, 1961.
	Supplement No. 2 to above	Assignment	Mar. 24, 1961.
CI61-1678	H. C. and Gertrude B. Andrewski FPC Gas Rate Schedule No. 2.	Basic Contract	Feb. 3, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1693	Great Western Drilling Company FPC Gas Rate Schedule No. 4.	Basic Contract	Apr. 24, 1961.
	Supplement No. 1 to above	Assignment	Apr. 1, 1961.
CI61-1711	Gulf Oil Corporation FPC Gas Rate Schedule No. 222.	Basic Contract	May 2, 1961.
	Supplement No. 1 to above	Letter Agreement	Mar. 20, 1961.
	Supplement No. 2 to above	Assignment	May 8, 1961.
CI61-1712	Viersen & Cochran (Operator), *et al.* FPC Gas Rate Schedule No. 4.	Basic Contract	Feb. 10, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1738	Herman Singer FPC Gas Rate Schedule No. 1	Basic Contract	Feb. 2, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1746	Kidd Williams Production Corporation (Operator), *et al.* FPC Gas Rate Schedule No. 1.	Basic Contract	Mar. 13, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1747	Kidd Williams Production Corporation (Operator), *et al.* FPC Gas Rate Schedule No. 2.	Basic Contract	Mar. 13, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.

Docket No.	Rate schedule designation	Description of document	Date of document
CI61-1785	John H. Burkhardt and Herman Burkhardt FPC Gas Rate Schedule No. 1.	Basic Contract	Feb. 9, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI61-1792	L. B. Jackson Company (Operator), *et al.* FPC Gas Rate Schedule No. 2.	Basic Contract	Apr. 21, 1961.
	Supplement No. 1 to above	Assignment	May 9, 1961.
CI61-1813	Alma McCutchin, *et al.* FPC Gas Rate Schedule No. 1.	Basic Contract	Feb. 15, 1961.
	Supplement No. 1 to above	Assignment	Mar. 24, 1961.
CI62-569	Texaco Inc. FPC Gas Rate Schedule No. 253	Basic Contract	Sept. 20, 1961.
	Supplement No. 1 to above	Assignment	Oct. 4, 1961.
CI62-570	Russell Maguire (Operator), *et al.* FPC Gas Rate Schedule No. 9.	Basic Contract	June 19, 1961.
	Supplement No. 1 to above	Assignment	June 28, 1961.
CI62-938	Sondau Oil and Gas Company, Inc., *et al.* FPC Gas Rate Schedule No. 1.	Basic Contract	May 29, 1961.
	Supplement No. 1 to above	Assignment	June 2, 1961.

Applicants shall notify the Commission of the date of commencement of deliveries under the applicable rate schedules.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

SOCONY MOBIL OIL COMPANY, INC., DOCKET NO. G–13780

ORDER GRANTING MOTION FOR STAY

(Issued March 30, 1962)

On February 9, 1962, 27 FPC 347, this Commission issued its order in this proceeding reducing the initial price, issuing a permanent certificate of public convenience and necessity, and directing refunds. On March 2, 1962, Socony Mobil Oil Company, Inc. filed a motion for stay of such provisions of said order as pertain to price and to refunds until 60 days after final action by the Commission upon Socony's application for rehearing, and until after final disposition of any petition for judicial review of the final order of the Commission herein. On the same day Socony filed its application for rehearing.

We have considered Socony's motion for stay, and find, as we did in our order of March 12, 1962, in *Continental Oil Co.*, Docket Nos. G–11024, *et al.* (*Catco*), that the motion for stay should be granted in part. We do not believe that the public interest will be adversely affected by granting a stay for a period of 60 days after our final action upon Socony's application for rehearing.

The Commission finds:

Good cause exists for granting Socony's motion for stay of ordering paragraphs (A), (C), and (D) of the order issued February 9, 1962, herein, for a period of 60 days following the Commission's final action upon the application for rehearing filed herein.

The Commission orders:

The conditions and requirements set forth in ordering paragraphs (A), (C), and (D) of the order issued February 9, 1962, to and as a part of the permanent certificate of public convenience and necessity issued thereby, and the compliance of Socony, are hereby stayed until 60 days after final action by the Commission upon the application for rehearing filed in these proceedings.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

CALIFORNIA ELECTRIC POWER COMPANY, PROJECT NOS. 344, 1388, 1389, 1390, AND 1394

ORDER DETERMINING AND DIRECTING ESTABLISHMENT AND MAINTENANCE OF AMORTIZATION RESERVES

(Issued April 2, 1962)

This is an amortization reserve proceeding pursuant to Section 10(d) of the Federal Power Act[1] involving five hydroelectric projects owned and operated by California Electric Power Company; specifically, licensed Project Nos. 344, 1388, 1389, 1390, and 1394. It was initiated by the staff through a comprehensive field examination of the books, records and other data of the Licensee, California Electric Power Company.

Staff proposes that the Commission, pursuant to Section 10(d) of the Act and Articles 17, 20, 22, 20, and 25 of the respective licenses for Project Nos. 344, 1388, 1389, 1390, and 1394, determine: the amount of Licensee's "surplus earnings" from project No. 344 for the period from January 16, 1944 through December 31, 1958, to be credited to Account 264, Amortization Reserve—Federal,[2] to be zero dollars, and the amounts of Licensee's "surplus earnings" from Project Nos. 1388, 1389, 1390, and 1394, for the period from December 1, 1956, through December 31, 1958, to be credited to Account 264 to be $303.52, $389.51, $43.83, and $763.10, respectively.

Article 17 of the license for Project No. 344 provides as follows:

> After the first twenty years of operation of said project under this license, out of surplus earned thereafter, if any, accumulated in excess of a specified reasonable rate of return upon the actual, legitimate investment in said project, all as defined in and determined by the provisions of Regulation 17 of said rules and regulations of the Commission, the licensee shall establish and maintain amortization reserves which reserves shall, in the discretion of the Commission, be held until the termination of the license or be applied from time to time in reduction of the net investment. Such specified rate of return shall, subject to the proviso of Paragraph A, Section 3 of said regulation, be one and one-half (1½) times the weighted average annual interest rate payable on the par value of the bona fide interest-bearing debt actually outstanding, in whole or in part, on account of project property at the beginning of the period of amortization and of each calendar year thereafter; such weighted average annual interest rate being determined as provided in Paragraphs B and C of Section 3 of said Regulation 17: *Provided*, That, if at the beginning of the period of amortization or of any calendar year thereafter, the outstanding interest-bearing debt on account of the

[1] Section 10(d) provides "[t]hat after the first twenty years of operation, out of surplus earned thereafter, if any, accumulated in excess of a specified reasonable rate of return upon the net investment of a licensee in any project or projects under license, the Licensee shall establish and maintain amortization reserves, which reserves shall, in the discretion of the Commission, be held until the termination of the license or be applied from time to time in reduction of the net investment. Such specified rate of return and the proportion of such surplus earnings to be paid into and held in such reserves shall be set forth in the license."

[2] Account references are to account numbers and titles prescribed in the Commission's revised Uniform System of Accounts for Public Utilities and Licensees effective January 1, 1961.

project under license, together with any other works or property operated in connection therewith, is less than 25 percent of the actual legitimate investment in said project, then and in such event for the calendar year next following the specified rate of return shall be two (2) times the legal rate of interest in the State of California.

Subject to the provisions of Section 6 of said regulation, the following proportions of such surplus earnings shall be paid into and held in such amortization reserves: Of all surplus earnings up to and including 2 percent upon the actual, legitimate investment, 30 percent thereof shall be so paid; of all surplus earnings in excess of 2 percent and not in excess of 4 percent upon such investment, 50 percent thereof shall be so paid; of all surplus earnings in excess of 4 percent and not in excess of 6 percent, 70 percent thereof shall be so paid; and of all surplus earnings in excess of 6 percent, 90 percent thereof shall be so paid; Provided, That if at the end of any calendar year of the amortization period the commission shall find that the accumulated earnings of said project during the period of operation, including the first twenty (20) years thereof, have not yielded a fair return upon the actual, legitimate investment in said project, the proportion of such surplus earnings for such calendar year and for succeeding calendar years to be paid into such amortization reserves shall be ten (10) percent thereof until such time as the accumulated earnings of said project represent, in the judgment of the Commission, a fair return upon such investment for such period of operation.

Articles 20, 22, 20, and 25 of the respective licenses for Project Nos. 1388, 1389, 1390, and 1394 provide as follows:

> After the first 20 years of operation of the project, six percent per annum is the specified * * * rate of return on the net investment in the project under license for determining surplus earnings, in accordance with the provisions of Section 10(d) of the Act, for the establishment and maintenance of amortization reserves to be held until the termination of the license, or, in the discretion of the Commission, to be applied from time to time in reduction of the net investment in * * * project, and one-half of all surplus earnings in excess of six percent per annum received in any calendar year shall be paid into * * * such amortization reserves.

Licensee's Project No. 344 was placed in commercial operation on January 16, 1924, and therefore entered the amortization reserve period at the beginning of its twenty-first year of operation, January 16, 1944. Commercial operation of Project Nos. 1388, 1389, 1390, and 1394, which were already constructed, commenced under license on December 1, 1936, making the initial dates of the respective amortization reserve periods for those projects December 1, 1956. The license for Project No. 344 was issued originally pursuant to Section 4(d) of the Federal Water Power Act on April 27, 1923, for a period of 50 years to the San Gorgonia Power Company (name later changed to San Gorgonio Power Company), and subsequently acquired by the present Licensee. The licenses for Project Nos. 1388, 1389, 1390, and 1394 were issued pursuant to Section 4(e) of the Federal Power Act, and each became effective for a period of 50 years commencing December 1, 1936.

The five projects are located within the State of California and are physically operated by the Licensee as an integral part of an interconnected system that includes an additional hydroelectric generating plant not under Commission license, steam production plants and a network of transmission and distribution systems. In addition, the Licensee receives certain of its electric energy requirements by purchase from other sources or through power pool or interchange

arrangements with other companies. The electric energy generated by the projects is intermingled and distributed in Licensee's system with energy from its other sources of supply. Licensee operates in southeastern California and southwestern Nevada and Arizona.

Consistent with Licensee's method of physical operation of the above projects, its accounts, books and records do not show any particular earnings specifically associated therewith or derived therefrom. The same is true of Licensee's other generating or purchased power resources. In these circumstances, staff proposes that the Commission determine Licensee's respective "surplus earnings" from Project Nos. 344, 1388, 1389, 1390, and 1394 as follows:

(1) Impute to the project during the respective fiscal periods concerned herein the particular earned rate of return which Licensee derived from its electric department utility operations as a whole during that period when computed in accordance with applicable precedents of this Commission;

(2) In the given fiscal period, determine the dollar excess, if any, of the project earnings, computed by applying the particular imputed earned rate of return to the average project net investment during the same period, over the project specified return, computed by applying the specified rate of return for the same period to (a) the project net investment as of the beginning of the same period for Project No. 344, and (b) the project net investment averaged for the beginning and end of the same period for Project Nos. 1388, 1389, 1390, and 1394; such excess to be considered Licensee's "surplus earnings" during the particular period.

The following tabulation shows the "surplus earnings" of the five projects during the amortization reserve periods covered by the staff's examination, computed in this manner, and the portions of such earnings to be credited to the respective amortization reserves for the various projects:

Project No. 344

Period	Earnings in excess of specified return and accumulated deficit		
	Surplus earnings	Accumulated deficit [1]	Credits to account 264
1/16/44 to 12/31/44	($46,623.88)	($46,623.88)	
1945	(47,107.12)	(93,731.00)	
1946	(45,439.84)	(139,170.84)	
1947	(43,688.63)	(182,859.47)	
1948	(42,178.91)	(225,038.38)	
1/1/49 to 10/31/49	(33,452.57)	(258,490.95)	
11/1/49 to 12/31/49	1,016.07	(257,474.88)	
1950	3,164.84	(254,310.04)	
1951	711.37	(253,598.67)	
1952	5,661.33	(247,937.34)	
1953	2,827.99	(245,109.35)	
1954	2,266.13	(242,843.22)	
1955	3,948.56	(238,894.66)	
1956	4,097.87	(234,796.79)	
1957	1,419.66	(233,377.13)	
1958	1,816.25	(231,560.88)	
Total	(231,560.88)	(231,560.88)	

Project No. 1388

12/1/56 to 12/31/56	$607.04		$303.52
1957	(4,367.61)	($4,367.61)	
1958	3,917.85	(449.76)	
Total	157.28	(449.76)	303.52

See footnote at end of table.

Project No. 1389

Period	Earnings in excess of specified return and accumulated deficit		
	Surplus earnings	Accumulated deficit[1]	Credits to account 264
12/1/56 to 12/31/56	$779.02		$389.51
1957	(5,884.40)	($5,884.40)	
1958	5,371.88	(512.52)	
Total	266.50	(512.52)	389.51

Project No. 1390

12/1/56 to 12/31/56	$87.66		$43.83
1957	(595.02)	($595.02)	
1958	467.99	(127.03)	
Total	(39.37)	(127.03)	43.83

Project No. 1394

12/1/56 to 12/31/56	$1,526.20		$763.10
1957	(11,701.18)	($11,701.18)	
1958	10,955.17	(746.01)	
Total	.780.19	(746.01)	763.10

[1] The large deficiency of earnings below the specified rate of return for project No. 344 is due to the fact that, during the period from January 16, 1944, the beginning of the project amortization reserve period, to November 1, 1949, the date of transfer to California Electric Power Company, the then licensee, San Gorgonio Electric Corporation, had (1) a net operating loss each year, and (2) a high specified rate of return. San Gorgonio had no outstanding interest-bearing debt on account of the project during this period. Therefore, in accordance with the proviso of Article 17 of the license, the specified rate of return was two times the legal rate of interest (7 percent) in California, or 14 percent. After the transfer of the license to California Electric Power Company on November 1, 1949, the project property became subject to the new licensee's bond mortgage indenture; and, accordingly, the new licensee's interest-bearing debt was outstanding on account of the project, and the specified rate of return was one and one-half times the weighted average annual interest rate.

In developing Licensee's yearly actual earned rate of return, the staff derived rate base for the Company's entire electric department operations for any given year is based upon average of beginning and end-of-year balances of electric plant in service (original cost), less related book depreciation reserves, contributions in aid of construction, customer advances for construction, and advance deposits for temporary installations for electric service, plus an allowance for working capital; the last being computed on the basis of a cash allowance equal to one-eighth of cash operating expenses (exclusive of purchased power expense and certain other items) for the particular year concerned, plus average balances of materials and supplies and prepayments, less average available advance collections of Federal income taxes exclusive of accruals attributable to Federal taxes deferred.

The Project No. 344 and other properties of San Gorgonio Electric Corporation were acquired by California Electric Power Company as of November 1, 1949, at a price less than depreciated original cost by $139,636.50. By order issued December 4, 1950, in Docket No. E–6222 (9 FPC 1287), the Commission authorized the recording of the credit amount of $139,636.50 in Account 100.5 (now 114), Electric Plant Acquisition Adjustments, and the disposition thereof by monthly credits of $581.82 to Account 505 (now 406), Amortization of Electric Plant Acquisition Adjustments, and offsetting charges to Account 252 (now 115), Reserve for Amortization of Electric Plant Acquisition Adjustments. The staff has excluded the credit balance in Account 100.5 and the debit balance in Account 252

from the rate base, but has included the monthly amortization credits to Account 505 in the computation of net electric operating income.

Staff treatment of Licensee's Federal income taxes reflects a normalization of the amount of income taxes deferred by Licensee pursuant to Sections 168 and 167 of the Internal Revenue Code of 1954, for the years for which such deferrals were recorded, in determining Licensee's net electric department operating income. Deferred State corporate franchise taxes, which are based upon the company's income for the preceding year, were treated in the same manner as deferred Federal income taxes.

Upon the conclusion of the staff examination, conferences were held between the staff and representatives of the Licensee at which agreement, subject to Commission approval, was reached as to the respective amounts of the "surplus earnings" of the five projects, as well as the portions of such earnings to be credited to Licensee's Account 264, as indicated above.

Licensee, by letter dated December 7, 1960, confirmed its agreement in the above matter and concurs that the Commission determine the amounts of "surplus earnings" to be credited to Account 264, as set forth above.

While the treatment herein of deferrals of income taxes conforms to our Uniform System of Accounts and certain prior Commission precedents and is accepted for the purposes of this determination of excess earnings, we do not necessarily endorse such treatment in principle and reserve the right to reexamine such treatment. We approve the instant determination for past periods inasmuch as any change in Commission policy would not be made retrospectively.

The Commission finds:

(1) The Federal Power Act [Section 10(d)] and Article 17 of the license for Project No. 344 require that Licensee establish and maintain amortization reserves with respect to that project wherein:

> Subject to the provisions of Section 6 of said regulation, the following proportions of such surplus earnings shall be paid into and held in such amortization reserves: Of all surplus earnings up to and including 2 percent upon the actual, legitimate investment, 30 percent thereof shall be so paid; of all surplus earnings in excess of 2 percent and not in excess of 4 percent upon such investment, 50 percent thereof shall be so paid; of all surplus earnings in excess of 4 percent and not in excess of 6 percent, 70 percent thereof shall be so paid; and of all surplus earnings in excess of 6 percent, 90 percent thereof shall be so paid: *Provided*, That if at the end of any calendar year of the amortization period the Commission shall find that the accumulated earnings of said project during the period of operation, including the first twenty (20) years thereof, have not yielded a fair return upon the actual, legitimate investment in said project, the proportion of such surplus earnings for such calendar year and for succeeding calendar years to be paid into such amortization reserves shall be ten (10) percent thereof until such time as the accumulated earnings of said project represent, in the judgment of the Commission, a fair return upon such investment for such period of operation.

(2) The Federal Power Act (Section 10(d)) and Articles 20, 22, 20 and 25 of the licenses for Project Nos. 1388, 1389, 1390, and 1394, respectively, require that Licensee establish and maintain amortization reserves with respect to those projects wherein:

> After the first 20 years of operation of the project, six percent per annum is the specified * * * rate of return on the net investment in the project under license for determining surplus earnings, in accordance with the provisions of Section 10(d) of the Act, for the establishment and mainte-

nance of amortization reserves to be held until the termination of the license, or, in the discretion of the Commission, to be applied from time to time in reduction of the net investment in * * * project, and one-half of all surplus earnings in excess of six percent per annum received in any calendar year shall be paid into * * * such amortization reserves.

(3) The first 20 years of operation of Project No. 344 under license ended as of January 15, 1944; and the first 20 years of operation of Project Nos. 1388, 1389, 1390, and 1394 under license ended as of November 30, 1956.

(4) The computation of Licensee's respective "surplus earnings" from Project Nos. 344, 1388, 1389, 1390, and 1394, subsequent to those dates and the portions thereof to be credited to Account 264, in the manner as proposed by the staff, all as described above, is reasonable and appropriate for the purposes of the Federal Power Act and the Commission licenses here concerned.

(5) For the period from January 16, 1944, through December 31, 1958, Licensee's surplus earnings for Project No. 344, and for the period from December 1, 1956, through December 31, 1958, Licensee's surplus earnings for Project Nos. 1388, 1389, 1390, and 1394, on an annual basis, are as set forth in tabular form in the recitals above, as well as the portions thereof required to be set aside for the projects in Account 264, Amortization Reserve-Federal.

(6) As of December 31, 1958, the credit balances required to be maintained by Licensee in Account 264, Amortization Reserve-Federal, for the five projects are as follows: Project No. 344—zero dollars; Project No. 1388—$303.52; Project No. 1389—$389.51; Project No. 1390—$43.83; and Project No. 1394—$763.10.

(6) Licensee's concurrence in the staff recommendations herein obviates the necessity for any public hearings in this matter prior to Commission action in accordance with those recommendations, as hereinafter provided.

The Commission orders:

(A) Licensee shall credit to Account 264, Amortization Reserve—Federal, by a charge to Account 216, Unappropriated Earned Surplus, the amount of zero dollars for Project No. 344 for the period from January 16, 1944 through December 31, 1958; and the amounts of $303.52, $389.51, $43.83, and $763.10 for the period from December 1, 1956 through December 31, 1958, for Project Nos. 1388, 1389, 1390, and 1394, respectively; all as shown in the tabulations hereinbefore set forth.

(B) Licensee shall, within 90 days from the issuance of this order, file three certified copies of its journal entries recording the above credits.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

GEORGIA POWER COMPANY, PROJECT NO. 2303

ORDER DENYING APPLICATION FOR PRELIMINARY PERMIT

(Issued April 2, 1962)

Application was filed on October 27, 1961, by Georgia Power Company (Applicant), of Atlanta, Georgia for a preliminary permit for thirty-six (36) months under sub-section 4(f) and Section 5 of the Federal Power Act (the Act), in order that the Applicant may secure and maintain priority for a license under the Act while studying the feasibility of developing the Flint River between river miles 230 and 270 for hydroelectric generating purposes and preparing an application for license.

By letter of January 19, 1962, the Office of the Chief of Engineers, Department of the Army, has advised that its studies and preparation of a comprehensive plan for developing the water resources involved are essentially complete. The aforesaid studies of the Corps of Engineers are made pursuant to Section 7 of the River and Harbor Act of July 24, 1946, and a June 1, 1948, resolution by the Committee on Public Works, United States Senate. The letter of January 19, 1962, from the Corps also states that: "Since a comprehensive plan for developing the water resources will be available in the near future, the Commission may wish to defer granting the permit."

On March 9, 1962, the Corps issued a notice of a report of the District and Division Engineers for the development of the Flint River. The report contains plans for three developments for the reach of the Flint River in which the applicant proposed to study the feasibility of development for hydroelectric generating purposes. The notice of the Corps describes these three developments, as follows:

Spewrell Bluff Dam. At river mile 263.4 above the mouth of the Flint, about 9 miles west of Thomaston. A dam with a maximum height of about 180 feet would form a reservoir of 16,800 acres at normal full-pool-elevation 700 above mean sea level. Between elevations 700 and 709 approximately 230,000 acre-feet of storage would be reserved for flood control. Between elevations 700 and 670 there would be 322,000 acre-feet stored for regulation of the flow for hydroelectric power production at the site and downstream. A 100,000 kilowatt hydroelectric power plant would be provided. The estimated Federal first cost of the project is $63,200,000.

Lazer Creek Dam. At mile 255.7 about 8 miles southwest of Thomaston. A dam with a maximum height of about 142 feet would form a reservoir of about 9,000 acres at normal full-pool-elevation 543 and would back water to Spewrell Bluff Dam. Between elevations 543 and 547 a storage of 45,000 acre-feet would be for flood control. A power plant of about 87,000 kilowatts would be provided. The estimated Federal first cost of the project is $40,400,000.

Lower Auchumpkee Creek Dam. At mile 233.4 about 18 miles southeast of Thomaston. A dam with a maximum height of about 130 feet would form a reservoir of about 15,600 acres at normal full-pool-elevation 417 and would back water to the Lazer Creek Dam. Between elevations 417 and 425 a storage of 145,000 acre-feet would be for flood control. A power plant of about 81,000 kilowatts would be provided. The estimated Federal first cost of the project is $48,300,000.

The purpose of a preliminary permit is to grant the permittee priority for filing an application for a license, but this priority is not available merely for the asking. It is granted in a situation where the feasibility of a project in a particular stretch of a river has not as yet been demonstrated. It gives the permittee a priority over other non-Federal parties in order to encourage the investigations of projects which otherwise might never be investigated or built. In the instant case, the engineering and economic studies for developing the reach of the Flint River for which the Applicant seeks a permit have just been completed by the District and Division Engineers who recommend that these three projects be constructed by the United States as the first phase of the comprehensive plan described in the report. The studies which a preliminary permit are designed to encourage have thus already been made at public expense and should therefore be available on an equal basis to any party which may wish to develop these water resources in the event Federal development is not authorized. Applicant like all other potential developers

has access to these studies and may of course file an application for a license without a prior preliminary permit. We conclude Applicant has not demonstrated a justification for a proposed preliminary permit.

Moreover, the comprehensive report discussed above is now under review by the Board of Engineers for Rivers and Harbors. It is anticipated that the Chief of Engineers will soon submit a report to this Commission for its review and comments, particularly with respect to the power features of the proposed plan of development. In its present form the report contemplates Federal development of these water resources.

Section 7(b) of the Federal Power Act declares:

> Whenever, in the judgment of the Commission, the development of any water resources for public purposes should be undertaken by the United States itself, the Commission shall not approve any application for any project affecting such development, but shall cause to be made such examinations, surveys, reports, plans, and estimates of the cost of the proposed development as it may find necessary, and shall submit its findings to Congress with such recommendations as it may find appropriate concerning such development.

We have not formed any judgment at this stage concerning the desirability of Federal development. No record has been made on this question and, as indicated above, the Chief of Engineers' report is not yet available to us. However, in light of the policy declared in Section 7(b) it does not seem appropriate to grant the preliminary permit sought by the Applicant when we shall soon have occasion to consider the question of Federal development. Should we conclude after reviewing the report of the Corps of Engineers that Federal construction is the appropriate way to develop the Flint River, it would then be plainly inconsistent with the policy of Section 7(b) to grant a permit; and it seems equally unwise to grant such a permit at the threshold of consideration of the question of Federal development, especially in view of the caution of the construction agency against granting a permit at this time.

In response to notice of the application, several communications have been received in support of the application and several have been received in opposition.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Federal Power Act, that the application for preliminary permit be denied.

The Commission orders:

The application for a preliminary permit for Project No. 2303, is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

UTAH POWER & LIGHT COMPANY, PROJECT NO. 675

ORDER ACCEPTING SURRENDER OF LICENSE (MAJOR)

(Issued April 2, 1962)

Application was filed August 28, 1956, by Utah Power & Light Company, licensee for major Project No. 675, for surrender of its license for the project pursuant to Section 6 of the Federal Power Act.

The project, known as the Battle Creek project, was located on Battle Creek and Blue Cliffs Creek and affected lands of the United States within the Uinta National Forest in Utah County, Utah.

According to the application, the existing 24-inch wood stave pipe line is 45 years old and needs to be replaced, but replacement is prohibitive under present operating and economic conditions due to labor, material and extensive energy costs, and energy can be supplied more economically from other points in the licensee's interconnected system. Therefore, the licensee concludes it is not justified in operating and maintaining the Battle Creek plant at which in 1955 the cost of energy was 14.120 mills per kilowatt-hour.

The Chief, Forest Service, acting for the Secretary of Agriculture, who has supervision over the Uinta National Forest, has reported, by letter dated December 6, 1961, that all water power generating facilities have been removed and that the national forest lands involved have been restored to a condition satisfactory to the Service, and there is no objection to surrender of the license for the project.

The licensee has returned its copy of the license instrument and annual charges under the license for the project have been paid through December 31, 1960.

The Commission finds:

(1) Public notice of the filing of the application has been given and no protests thereon have been received.

(2) Acceptance of surrender of the license for the project is appropriate as hereinafter provided.

The Commission orders:

Surrender of the license for major Project No. 675 is accepted, effective as of December 31, 1961, subject to the payment of annual charges under the license for the project through said date in the amount of $184.20 within 30 days of rendition of a bill therefor by the Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

REJECTION OF SALES CONTRACTS CONTAINING INDEFINITE ESCALATION CLAUSES AND OF APPLICATIONS RELYING UPON SUCH CONTRACTS FOR GAS SUPPLY, DOCKET NO. R–203

ORDER 242

ORDER DENYING APPLICATIONS FOR REHEARING

(Issued April 4, 1962)

Subsequent to the issuance on February 8, 1962, of Order No. 242, 27 FPC 339, which prescribed certain amendments to the Commission's Regulations under the Natural Gas Act, applications for rehearing, as noted below, were timely filed. All such applications requested us to reconsider our action and vacate or revoke that order.

The points urged in the applications are substantially the same as those heretofore presented to the Commission in the written submittals made pursuant to the notice of proposed rulemaking issued herein on October 10, 1961 (26 F.R. 9732). They were fully considered by the Commission prior to the issuance of the order. Furthermore, the points are, in large part, the same as those urged in Docket No. R–153 both prior and subsequent to the issuance of our Orders Nos. 232 and 232–A. Accordingly, there is no occasion for further elaboration of our views.

The Commission finds:

No new facts or principles of law have been assigned in the several applications for rehearing which either were not fully considered by the Commission

prior to the issuance of Order No. 242, or, having now been considered, warrant further hearing, modification or revocation of such order or the regulations promulgated thereby.

The Commission orders:

(A) The application for rehearing filed herein by Hunt Oil Company (and others therein named) on March 5, 1962, is hereby denied.

(B) The application for rehearing filed by Pan American Petroleum Corporation of March 7, 1962, is hereby denied.

(C) The application for rehearing and reconsideration filed herein by Humble Oil & Refining Company on March 8, 1962, is hereby denied.

(D) The application for rehearing filed herein by Shell Oil Company on March 8, 1962, is hereby denied.

(E) The petition for rehearing filed herein by The Superior Oil Company on March 8, 1962, is hereby denied.

(F) The application for rehearing filed herein by The Atlantic Refining Company on March 9, 1962, is hereby denied.

(G) The application for rehearing filed herein by Sun Oil Company on March 9, 1962, is hereby denied.

(H) The application for rehearing and reconsideration filed herein by Continental Oil Company on March 12, 1962, is hereby denied.

(I) The application for rehearing and reconsideration filed herein by Phillips Petroleum Company on March 12, 1962, is hereby denied.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, and L. J. O'Connor, Jr.

PACIFIC POWER & LIGHT COMPANY, DOCKET NO. E-7025

SUPPLEMENTAL ORDER AUTHORIZING THE ISSUANCE OF COMMON STOCK

(Issued April 5, 1962)

(ii) By order issued March 28, 1962, 27 FPC 620, in the above-entitled matter, the Commission authorized Pacific Power & Light Company (Applicant) to issue and sell up to 696,695 shares of its Common Stock, par value $3.25 per share, through an underwritten subscription offering, subject, among others, to the provisions set forth in paragraph (B) of that order, as follows:

(B) The proposed issuance and sale of Common Stock at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of the Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegram as contemplated by Section 34.9 of the Regulations;

(ii) The Commission, by further order, shall have approved the subscription price per share to be received by Applicant for the Common Stock and the compensation to be paid to underwriters under the proposed arrangement as described above.

Applicant, on April 5, 1962, filed an amendment, pursuant to the requirements of the afore-mentioned Commission order, in which it states that it has fixed $27.00 per share as the subscription price to be received by Applicant for 676,497 shares of Common Stock and that it proposes to accept, as representing the

lowest aggregate amount of compensation to be paid by the Applicant to the underwriters, the bid of Kidder, Peabody & Co. to purchase all of the unsubscribed shares of the proposed issuance of Common Stock at the subscription price for an aggregate compensation of $236,097.45.

The Commission finds:

(1) Applicant has satisfactorily complied with the requirements of paragraph (B) of the Commission's order issued March 28, 1962, in the above docket, and the subscription price to be received by the Applicant for the Common Stock and the compensation to be paid to the underwriters under the bid referred to above are reasonable.

(2) The proposed issuance of Common Stock, as hereinafter authorized will be for a lawful object, within the corporate purposes of Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance of service by Applicant as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The subscription price to be received by the Applicant for the Common Stock and the compensation to be paid to the underwriters under the bid referred to above are approved as reasonable.

(B) The proposed issuance and sale of Common Stock referred to above, upon the terms and conditions, and for the purposes specified in the application, as supplemented by the amendment referred to above, are hereby authorized subject only to the provisions of Paragraphs (A), (C), (D), and (E) of the Commission's order issued March 28, 1962, in the above docket.

Commissioner Morgan *dissenting* stated: My objections to this issue, as expressed in my dissent to the order, have not been answered or satisfied and I therefore do not concur in this order under the prevailing conditions.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. G-11980

ORDER DENYING REHEARING AND FURTHER ORAL ARGUMENT

(Issued April 5, 1962)

On February 6, 1962, we issued an opinion (No. 352) and accompanying order determining principles and methods of allocation of costs to zones and related issues in the proceeding in Docket No. G-11980.

Applications for rehearing have been filed by the Columbia Companies [1] and by the New England interveners.[2] In addition to rehearing, the New England interveners in their application and the Columbia Companies by separate document request clarification of specified portions of the Commission Opinion. Columbia has also requested further oral argument. Brooklyn Union Gas Company, Public Service Electric and Gas Company, Consolidated Edison Company of New York, Inc., and Tennessee Gas Transmission Company have filed opposition to the request for further oral argument. The Pennsylvania Public Utility Commission

[1] Manufacturers Light and Heat Company, The Ohio Fuel Gas Company and United Fuel Gas Company.

[2] A complete list of the New England companies is set forth in their petition, p. 1, footnote No. 1.

filed statements joining the Columbia Companies in both their application and petition for rehearing and in their motion for further oral argument.

In the application for rehearing Columbia states *inter alia* that the Commission erred in: (1) the method of assigning costs to Storage Service (SS–5) and Peaking Services (PS–G); (2) adopting the historical revenue patterns;[3] and (3) adopting the Mcf-mile over the zone-by-zone method of allocation.

In support of the allegation that the Commission erred in the assignment of costs to SS–5 and PS–G services, Columbia argues that the Commission is precluded from crediting revenues to these services because of prior orders in Docket Nos. G–11107 and G–11980, and argument by the Commission's Solicitor before the court. It is apparent from the Commission's and the Solicitor's prior statements, read in context, that these statements do not commit the Commission to a particular method of determining costs for these services. Rather, they properly leave the question of the determination of these costs until such time as all the facts and interrelationships can be considered. In Opinion No. 352, upon consideration of all the facts, equities and benefits, we allocated costs to these classes of service which would recover all of the incremental costs of these services and a substantial amount of system costs which would otherwise be borne by regular service. The method employed is both fair and reasonable in the light of the record before us.

Columbia alleges additionally that the Commission erred in its finding of incremental costs applicable to the PS–G service. This assertion appears to rest upon a misinterpretation of the concept of incremental costs. Thus, Columbia seems to imply that incremental cost would include fixed charges. Incremental costs, as we have used them, include only the out-of-pocket costs (compression, purchased gas, etc.). We adhere to this view.

Columbia also contends that the Commission erred in finding that no additional facilities were required to render storage service and peak service. This contention is without merit. While it is a fact that facilities were constructed which ultimately render these services, such facilities were not constructed for the purpose of rendering PS–G service, nor were additional facilities necessary to render the SS–5 service authorized. (Docket Nos. G–10804 and G–11107, 19 FPC 558 and 21 FPC 70.) These services have been authorized to make the best use of existing facilities.

In its petition Columbia reiterates its position opposing the Mcf-mile and favoring the zone-by-zone method of allocation. We have fully considered Columbia's argument made during hearing, in its briefs, exceptions and in two oral arguments. Its position is abundantly clear and does not alter our conclusion.

However, Columbia points out a correction that should be made to the more recent volumetric data of the various zones used in our Opinion. The data used did not include the volumes delivered to the Gabe extraction plant in the Central zone. For this reason the volumes for the Central zone are understated by 7,665,000 Mcf annually. This correction, however, does not affect our conclusion:

> * * * In view of this indicated growth of the *New England* load, an adjustment for load density in that zone does not appear to be necessary. [Emphasis added.]

Both Columbia and New England request clarification of our language with respect to the future application of the historical revenue pattern. So that there

[3] In its concurrent motion for clarification of specified portions of Opinion No. 352, Columbia contends that the portion of that Opinion prescribing the manner of application of the historical revenue is ambiguous and open to conflicting interpretations. That contention is dealt with below.

will be no misunderstanding, we intend that the G–5259 rates be applied to the volumes of gas sold in the respective periods involved in the G–11980, G–17166, and G–19983 proceedings to determine the historical revenue pattern. Also, it is contemplated that the transition from the historical revenue pattern to straight Mcf–mile costs will take place after the period covered by the G–19983 proceeding. We contemplate that in any future case there will be no adjustment to reflect the historical revenue pattern, but do not foreclose the possibility that special circumstances in the future may require some adjustment.

In addition, the New England interveners argue that the Commission erred in: (1) segregating the lateral facilities in the New England zone, or that, even if segregation were proper, the Commission did so on an improper basis; and (2) determining demand responsibility on the basis of the three-day sustained peak rather than on the basis of average billing demands. Our reconsideration of their arguments indicates no error in our findings or conclusions.

Grant of Columbia's request for additional oral argument would be unwarranted. This case has been fully briefed and two oral arguments have been held.

The Commission finds:

(1) The afore-mentioned applications for Rehearing filed herein, set forth no new facts or principles of law which either were not fully considered by the Commission when it adopted its opinion and order issued February 6, 1962, in Docket No. G–11980, or which having now been considered warrant any change or modification of said order.

(2) Columbia's request for further oral argument should be denied.

The Commission orders:

(A) The afore-mentioned petitions for Rehearing of the Commission's opinion and order in Docket No. G–11980 issued February 6, 1962, are hereby denied.

(B) Columbia's request for further oral argument is hereby denied.

Commissioner Woodward *not participating*.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., and Charles R. Ross.

UNION OIL COMPANY OF CALIFORNIA, DOCKET NO. G–13997[1]

ORDER DENYING MOTION TO SEVER AND TERMINATE PROCEEDING

(Issued April 5, 1962)

Union Oil Company of California (Union Oil) has heretofore tendered for filing a proposed increased rate which was suspended and subsequently placed in effect subject to refund. The proposed increased rate, designated Supplement No. 5 to Union Oil's FPC Gas Rate Schedule No. 10, provides for an increase from 10.135¢ per Mcf to 11.1485¢ per Mcf, at 14.55 psia, for the sale of natural gas to El Paso Natural Gas Company, in the Dollarhide Field, Andrews County, Texas (Railroad District No. 8).

On January 31, 1962, Union Oil filed a motion to sever this proceeding from the proceedings in Docket No. AR61–1, *et al.*, and to terminate the proceeding in Docket No. G–13997. In support of its motion, Union Oil cites four proceed-

[1] Consolidated with the proceedings in Docket No. AR61–1, *et al.*, by order issued December 23, 1960, 24 FPC 1121.

ings, involving similar increases, which have been terminated.[2] Also cited is a presiding examiner's decision,[3] and the *Reef Fields* case.[4]

The cases cited by Union Oil are inapplicable to this proceeding, and do not support its position. The four cases listed in footnote 2 were terminated before the issuance of the Commission's Statement of General Policy No. 61–1, September 28, 1960, 24 FPC 818, which established area price levels for producer rates. The *Hunt* case, *supra*, presently pending before the Commission, was decided by the presiding examiner on a cost of service basis after a formal hearing in accordance with the *Phillips* case;[5] and the *Reef Fields* case is inapposite in view of the policy of the Commission as announced in the *Phillips* case and the Statement of General Policy No. 61–1.

Union Oil's increased rate exceeds the 11.0¢ per Mcf level for increased rates in Texas Railroad Commission District No. 8. The proceeding in Docket No. G–13997 has been consolidated with the Permian Basin area rate proceeding, Docket No. AR61–1, *et al.*, in which just and reasonable rates for that area will be determined. Accordingly, we conclude that Union Oil's motion to terminate should be denied.

The Commission finds:

(1) For the reasons hereinabove stated, Union Oil's motion to sever the proceeding in Docket No. G–13997 from the proceedings in Docket No. AR61–1 should be denied.

(2) For the reasons hereinabove stated, Union Oil's motion to terminate the proceeding in Docket No. G–13997 should be denied.

The Commission orders:

(A) Union Oil's motion to sever the proceeding in Docket No. G–13997 from the proceedings in Docket No. AR61–1, *et al.*, is hereby denied.

(B) Union Oil's motion to terminate the proceeding in Docket No. G–13997 is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

PACIFIC GAS TRANSMISSION COMPANY, DOCKET NO. CP62–59

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued April 6, 1962)

On September 11, 1961, as supplemented on September 28, 1961, and October 20, 1961, Pacific Gas Transmission Company (Applicant) filed an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation, as necessary, of taps and metering facilities at unspecified points along Applicant's 36-inch transmission line in Idaho, Washington and Oregon, in order to deliver to El Paso Natural Gas Company (El Paso), at such points, part of the gas

[2] The Pure Oil Company, Docket No. G–14049, order issued December 16, 1959; Getty Oil Company, Docket No. G–14033, order issued December 23, 1959; Cities Service Petroleum Company, Docket No. G–14885, order issued January 26, 1960; F. G. Blackwood, *et al.*, Docket No. G–14265, order issued June 30, 1960.

[3] Hunt Oil Company, Docket No. G–9065, *et al.*, decision issued October 2, 1961, 28 FPC 626.

[4] *Reef Fields Gasoline Corporation (Operator), et al.*, Docket No. G–14030, 19 FPC 351.

[5] *Phillips Petroleum Company*, Docket No. G–1148, *et al.*, Opinion No. 338, September 28, 1960, 24 FPC 537, at page 549.

Applicant has previously been authorized to transport for El Paso from Canada. Such facilities would be built only at locations where El Paso is or will be authorized by the Commission to sell gas to distributors for resale.

In its order of August 5, 1960, issued in Docket Nos. G–17350, *et al.*, the Commission authorized Applicant to construct and operate a 36-inch transmission line extending from the Canadian boundary at a point in Idaho to the Oregon-California border southeast of Klamath Falls, Oregon. That order also authorized Applicant to transport for El Paso a portion of the latter's Canadian gas from Canada to points along the 36-inch line in Idaho, Washington and Oregon, and, further, the order states "* * * at least 30,000 Mcf, peak day volumes, will be reserved specifically for applications for new service off the PGT line in Idaho, Washington and Oregon, filed within three years from the date such line is placed in service."

In Docket No. CP60–15 El Paso has pending an application for authority to build facilities to receive gas from Applicant's 36-inch line for sale to two distributors for resale in Klamath Falls and Bend, Oregon. The estimated cost of Applicant's proposed facilities at Klamath and Bend is $14,000 and $12,500, respectively. Applicant states that the estimated cost of similar facilities at any other point on its 36-inch line for delivery of gas to El Paso will not be more than $12,500 for each delivery point.

The cost of each tap will be borne by El Paso in accordance with Applicant's FPC Gas Tariff.

Applicant was granted temporary authorization by letter, dated December 11, 1961, to construct and operate facilities and to deliver natural gas at Klamath Falls and Bend.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 28, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, herein. On February 23, 1962, the Idaho Public Utilities Commission filed a notice of intervention in the subject docket. By letter filed March 5, 1962, the Idaho Commission advised that it had no objection to the granting of the subject application. No other petition to intervene or protest to the granting of the application has been received. No appearances, other than that of staff counsel, were entered at the hearing. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Pacific Gas Transmission Company, a California corporation, having its principal place of business in San Francisco, California, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order issued August 5, 1960, in Docket Nos. G–17350, *et al.* (24 FPC 134.)

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are proposed to be used in the transportation and delivery of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) The construction and operation of the facilities as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(4) The authorization hereinafter granted should be limited to construction during a period limited to three years from the commencement of operation of

Applicant's pipeline authorized in Docket Nos. G–17350, *et al.*, and only when El Paso has been authorized by the Commission to sell gas received at such facilities during such three-year period.

(5) Applicant is able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(6) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act and the Commission's Regulations thereunder that Applicant should submit a report, under oath, for each of the 3 twelve-month periods within 2 months after the end of each twelve-month period, giving all pertinent details of the construction of facilities hereinafter authorized, including location of each project, a description of facilities constructed for each project, and the actual final cost of each project.

(7) Expenditures for facilities for each individual project constructed pursuant to the authorization hereinafter granted should be limited to $12,500, with the exception of Applicant's project at Klamath Falls which should be limited to $14,000.

(8) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of said Regulations.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Pacific Gas Transmission Company to operate the proposed facilities in order to deliver natural gas to El Paso and to construct said proposed facilities during a period limited to three years from the commencement of operation of Applicant's pipeline authorized in Docket Nos. G–17350, *et al.*, and only when El Paso has been authorized by the Commission to sell gas received at such facilities during such three-year period, all as hereinbefore described and as more full described in the application, as supplemented, in this proceeding.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of such Regulations.

(C) Applicant shall submit a report, under oath, for each of the 3 twelve-month periods within 2 months after the end of each twelve-month period, giving all pertinent details of the construction facilities authorized in paragraph (A) above, including location of each project, a description of facilities constructed for each project, and final cost of each project.

(D) Total expenditures for facilities for each individual project constructed pursuant to the authorization granted in paragraph (A) above are hereby limited to $12,500, with the exception of Applicant's project at Klamath Falls which is hereby limited to $14,000.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

SHELL OIL COMPANY, DOCKET NO. G-13876

ORDER DENYING REHEARING AND GRANTING STAY

(Issued April 6, 1962)

Shell Oil Company filed on March 12, 1962, an application for rehearing of our "Order Requiring Additional Refund" issued February 13, 1962, and also a motion to stay the effectiveness of paragraphs (A) and (B) of said order pending action on shell's application for rehearing and until such time as matters raised in said application have been judicially determined. In support of its motion, Shell stated that such stay is necessary to preserve its rights and to prevent irreparable injury.

In our order accompanying Opinion No. 335, issued February 23, 1960, in *El Paso Natural Gas Company*, G-13862, *et al.*, 23 FPC 369, 380, affirmed *sub nom. Texaco Inc.* v. *FPC*, 290 F. 2d 149 (CA 5), we authorized Shell to sell to El Paso residue gas to be produced in certain fields in the Aneth area in San Juan County, Utah, at the rate of 17.7¢ per Mcf in lieu of the initial price contained in its contract with El Paso which Shell had been collecting, subject to refund, under temporary authorization issued on November 18, 1958. In its application for rehearing, Shell refers to certain provisions in its contract with El Paso and concludes that the 17.7¢ price is exclusive of tax reimbursement and that our order issued February 13, 1962 requiring additional refund is invalid " * * * in that it purports to require, without notice or hearing, a refund in addition to that required in the ordering paragraphs accompanying Opinion No. 335, * * *."

On May 18, 1960 Shell filed Supplement No. 4 to its Rate Schedule No. 178 to reflect an increase in the Utah occupation tax from 1% to 2% effective January 1, 1960, and the filing was accepted by the Commission with the refund conditions attached to the temporary authorization. The filing for tax reimbursement was based on the 20¢ contract price, which was then being collected under temporary authorization. Shell concedes that a part of the tax reimbursement should be refunded to El Paso and says that it stands ready to make such refund in the amount of $514.16, said sum being computed on the difference between the contract price and 17.7¢ per Mcf plus applicable tax reimbursement.

It appears that Shell misconstrues our order issued February 23, 1960, accompanying Opinion No. 335 and our order issued November 18, 1958, granting temporary authorization to sell gas to El Paso. The pertinent portions of those orders were applied in our order issued February 13, 1962 requiring additional refund.

Shell says further in its application for rehearing that on June 1, 1961, it received from El Paso the sum of $4,212.45 for the tax of 1960, that this is the only tax reimbursement that it has ever received under its Rate Schedule No. 178, and that the suggestion on page 2 of the order of which rehearing is sought that additional refund should approximate $7,500 apparently results from a misunderstanding of the nature and operation of the Utah tax. We would not expect Shell's tax refund to El Paso to exceed the amount of tax reimbursement received from El Paso under Shell's Rate Schedule No. 178, but we note that Shell did not offer to refund even that amount.

The action of the Commission in this matter does not preclude Shell from filing a supplement to its Rate Schedule No. 178, under the provisions of the Natural Gas Act and Section 154.94 of the Commission's Regulations, reflecting the increase of 1% in the Utah occupation tax.

The Commission finds further:

(1) The assignments of error and grounds for rehearing stated in Shell's application for rehearing set forth no new facts or principles of law which were not fully considered by the Commission when it issued the order of which rehearing is sought or which, having now been considered, warrant any change in said order.

(2) The enforcement of said order should be stayed until 60 days after the date of this order to allow Shell time to seek a review in court pursuant to Section 19(a) of the Natural Gas Act.

The Commission orders:

(A) Shell's application for rehearing of our "Order Requiring Additional Refund" issued herein on February 13, 1962, is denied.

(B) The enforcement of said order is hereby stayed until 60 days after the date of this order.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

SOCONY MOBIL OIL COMPANY, INC., DOCKET NO. G–13780

ORDER DENYING REHEARING

(Issued April 6, 1962)

Socony Mobil Oil Company, Inc., has filed an application for rehearing of our order of February 9, 1962, 27 FPC 347, herein. Most of Socony's objections closely parallel those of the CATCO companies in their application for rehearing of our Opinion No. 351 and order of January 22, 1962, in *Continental Oil Co.*, Docket Nos. G–11024 *et al.*, 27 FPC 96. We considered such objections fully in denying rehearing by order of March 22, 1962, in those proceedings, 27 FPC 592. See, also, our order of March 7, 1962, in *Texaco-Seaboard, Inc.*, Docket Nos. G–13169 *et al.*, 27 FPC 482.

Socony makes three additional contentions. It is noteworthy that despite previous opportunities Socony presents these arguments for the first time in the application for rehearing.

Socony objects on constitutional grounds to our refusal to base its initial price on a showing of its costs in the High Island field. Socony does not advocate field-by-field cost studies as an intelligent or appropriate approach to rate regulation under the Natural Gas Act. Socony would presumably oppose such an approach in the case of low cost fields. Socony does seem to claim, however, that our order deprives it of property without due process of law, in violation of the Fifth Amendment, if it reduces a single contract price to a level below "cost" in that field (albeit the price proposed by Socony is also claimed to fall under "costs" and most of the gas sold in the area brings a price no higher than that determined by our order). In our view, no constitutional question is presented until, at the very least, a company undertakes to prove that rates determined by us have resulted in reducing total revenues (from all fields) to an unreasonably low level. See *B. & O. R. Co.* v. *United States*, 345 U.S. 146.

Socony also claims that we should have told it what evidence to adduce in this proceeding, and that we should have recognized both the "unique" nature of High Island gas and its comparability to offshore Louisiana gas. Our order of September 25, 1961, herein, made clear our view that the High Island gas is

produced in Texas Railroad Commission District No. 3 and should be so regarded for purposes of initial price determination. Socony's bare assertion does not persuade us to apply Louisiana criteria to this Texas gas. Nor does the record support Socony's contention. There was testimony in the original hearing in 1958 suggesting that High Island was tied to sales of south Louisiana gas in contract negotiations with the purchaser; but, even if so interpreted, this testimony merely indicates some difficulty in marketing this production. Upon consideration of the evidence adduced, we find no compelling reason to allow Socony a higher price than is appropriate for other Texas production.

Finally, Socony suggests that it should be permitted to abandon the subject sale under Section 7(b) of the Natural Gas Act. Whether the public convenience and necessity would permit abandonment is a question not now before us; no application under Section 7(b) has been filed.

The Commission further finds:

The assignments of error and grounds for rehearing set forth in the application for rehearing filed herein on March 12, 1962, by Socony set forth no new facts or principles of law which were not fully considered by the Commission when it issued its order of February 9, 1962, or which, having now been considered, warrant modification.

The Commission orders:

The application for rehearing of the Commission's order issued February 9, 1962, filed by Socony is hereby denied.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

TEXAS EASTERN TRANSMISSION CORPORATION, DOCKET NO. CP62-156

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued April 6, 1962)

On January 4, 1962, as supplemented on January 29, 1962, Texas Eastern Transmission Corporation (Applicant) filed in Docket No. CP62-156 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the calendar year 1962, at a total cost not to exceed $4,000,000, with no single project to exceed a cost of $500,000, all as more fully set forth in the application, as supplemented.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its existing pipeline system new supplies of natural gas which will be purchased from producers thereof in various areas generally coextensive with said system.

The proposed facilities will be financed from funds on hand.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 27, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or notice of intervention has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission

render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Texas Eastern Transmission Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 10, 1947, in Docket No. G–880 (6 FPC 148).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas purchased from producers thereof during the calendar year 1962 as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit on or before March 1, 1963, a statement under oath, showing by projects: names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the actual final costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(6) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(7) The authorization hereinafter granted should be limited to construction during the calendar year 1962, and the total expenditures for facilities authorized to be constructed thereunder should be limited to $4,000,000 with no single project to exceed a cost of $500,000.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Texas Eastern Transmission Commission to construct during the calendar year 1962 the proposed facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, and to operate such facilities only to take natural gas from producers who have received authorization from the Commission to sell natural gas to Texas Eastern Transmission Corporation.

(B) Applicant shall submit, on or before March 1, 1963, a statement under oath, showing by projects: (a) names of fields connected, (b) estimates of gas

supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the actual final costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(C) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed thereunder are hereby limited to $4,000,000, with no single project to exceed a cost of $500,000.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

SENECA GAS COMPANY OF WEST VIRGINIA, INC., DOCKET NO. G–18442; ATLANTIC SEABOARD CORPORATION, DOCKET NO. CP62–67; SENECA GAS COMPANY OF WEST VIRGINIA, INC. vs. NAVGAS, INC., DEFENDANT, DOCKET NO. CP62–115; NAVGAS, INC., DOCKET NO. CP61–251

ORDER PERMITTING INTERVENTION

(Issued April 9, 1962)

On May 15, 1961, Seneca Gas Company of West Virginia, Inc. (Seneca) filed a petition for leave to intervene in Docket No. CP61–251.

Seneca alleges, among other things, that Navgas, Inc. by its application proposes to construct and operate substantially identical natural gas transmission and distribution facilities and to render substantially the same service and sales as those encompassed in and authorized by a certificate of public convenience and necessity issued to Seneca by the Public Service Commission of West Virginia on December 29, 1958, and which are the subject of Seneca's Section 7(a) application in Docket No. G–18442. Seneca asserts that Navgas, Inc.'s proposal is in conflict with the rights and duties conferred upon Seneca by the State of West Virginia. For this reason, Seneca says its economic interest in this proceeding is substantial.

Seneca also challenges the legality of Navgas, Inc.'s Section 7(a) application and refers to allegations contained in a petition to reject the application of Navgas, Inc. retendered[1] by Seneca concurrently with the filing of its petition to intervene.

On February 21, 1962, the United States Department of the Navy, acting through the Chief of the Bureau of Yards and Docks, Department of the Navy, filed a petition for leave to intervene in Dockets Nos. G–18442, CP62–67, and CP62–115, alleging:

1. The Department of the Navy is presently constructing a facility known as the Naval Radio Research Station at Sugar Grove in Pendleton County, West Virginia. In carrying out the vital defense mission of this facility it was determined

[1] Filed originally by Seneca on April 24, 1961, and rejected by the Commission's Secretary on May 5, 1961.

that natural gas would be required for the fuel needs of the Station. Following established contracting procedures, the contract covering the procurement of natural gas service was awarded to Navgas, Inc. ("Navgas"), of Charleston, West Virginia, and the formal contract was entered into as of June 15, 1960. Under the contract the contractor agreed to serve the Government exclusively and to provide for all of its natural gas requirements at the facility. The Government agreed to pay the contractor a connection charge upon the satisfactory completion of a twenty-six (26) mile pipeline which would connect with the transmission line of Atlantic Seaboard Corporation ("Seaboard") at a point in Hardy County, West Virginia. Navgas entered into a contract for the construction and installation of the pipeline and the same has now been completed, has been found satisfactory, and the connection charge has been paid.

2. The schedule of operations at the Station presently indicates that natural gas service will be required by October 1, 1962, and it is essential that no delays be encountered in obtaining the gas on or before that date. Any delays will seriously hamper the Department of the Navy in the performance of its defense mission.

3. Insofar as the application under Section 7(a) of the Natural Gas Act, as amended, filed by Seneca Gas Company of West Virginia, Inc. ("Seneca"), is concerned, a contract for natural gas service has been awarded to Navgas, as aforesaid. In view thereof, the Department of the Navy has no intention to procure natural gas from Seneca and consequently to the extent that Seneca's said application under Section 7(a) of the act refers to gas service to the Department of the Navy, any action taken by the Commission on said application should reflect the fact that Seneca's natural gas requirements, as stated in its application, should be reduced by the estimated volume of the Department of the Navy's procurement.

4. The Department of the Navy has advised Navgas and Seaboard that the Navy is vitally interested in the subject proceeding to the extent that it will fully support the application of Seaboard for a certificate of public convenience and necessity pursuant to Section 7(c) of the Natural Gas Act, as amended.

On March 16, 1962, Navgas, Inc., filed a petition for leave to intervene in each of Dockets Nos. G–18422, CP62–67, and CP62–115 alleging that it has on file Docket No. CP61–251, an application pursuant to Section 7(a) seeking an order requiring Atlantic Seaboard Corporation to supply its natural gas requirements and alleging further that Navgas, Inc., has entered into a firm contract with the Department of the Navy to supply natural gas requirements for the Naval Radio Research Station at Sugar Grove, West Virginia.

The Commission finds:

It is desirable to allow the several petitioners to intervene in the respective proceedings in which they seek to intervene in order that said petitioners may establish the facts and law from which the nature and validity of the alleged rights and interests of each of them may be determined and show what further action may be appropriate under the circumstances in the administration of the Natural Gas Act.

The Commission orders:

Petitioners, Seneca Gas Company, the United States Department of the Navy, and Navgas, Inc., are hereby permitted to become interveners in the respective proceedings in which they seek to intervene, subject to the rules and regulations of the Commission: *Provided, however,* That the participation of such petitioners shall be limited to matters affecting asserted rights and interests specifically set forth in their petitions for leave to intervene: *And provided further,* That

the admission of such petitioners shall not be construed as recognition by the Commission that they or any of them might be aggrieved because of any order or orders of the Commission entered in these proceedings.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

HOPE NATURAL GAS COMPANY, DOCKET NO. CP62-155; MISSISSIPPI RIVER FUEL CORPORATION, DOCKET NO. CP62-159

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued April 10, 1962)

On December 29, 1961, Hope Natural Gas Company (Hope) filed in Docket No. CP62-155 and on January 5, 1962, Mississippi River Fuel Corporation (Mississippi) filed in Docket No. CP62-159, respectively, applications pursuant to Section 7(c) of the Natural Gas Act for certificates of public convenience and necessity authorizing the sale of natural gas to American Louisiana Gas Company (American Louisiana), all as more fully set forth in the applications.

The proposed sales will be made from the Creole Field, Cameron Parish, Louisiana, at an initial rate of 18 cents per Mcf plus 1.5 cents per Mcf tax reimbursement, pursuant to a contract dated December 11, 1961, executed by and between Hope and Mississippi as sellers and American Louisiana as buyer.

Five leases in the Creole Field have been committed under the contract with American Louisiana. Hope has a 75 percent working interest in the leases and Mississippi has a 25 percent working interest.

Applicants propose to construct and operate field facilities in order to make the proposed sales. The cost is estimated to be $68,931, of which Hope will share 75 percent and Mississippi 25 percent.

Deliveries will be made at American Louisiana's meter station near its existing 16-inch transmission line extending between Cameron and Lowry, Louisiana. The contract provides for a daily take-or-pay-for quantity of 500 Mcf.

Temporary authorizations to make the proposed sales were granted to the respective Applicants by the Commission on February 6, 1962.

Pursuant to due notice, a public hearing was held in Washington, D.C., on March 29, 1962, respecting the matters involved in and the issues presented by the applications herein. No protest to the granting of the applications or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Hope Natural Gas Company, a West Virginia corporation having its principal place of business in Clarksburg, West Virginia, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 27, 1943, in Docket No. G-290 (3 FPC 994).

(2) Applicant, Mississippi River Fuel Corporation, a Delaware corporation having its principal place of business in St. Louis, Missouri, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of March 1, 1944, in Docket No. G-291 (4 FPC 535).

(3) The sales of natural gas hereinbefore described, as more fully described in the applications in this proceeding, will be made in interstate commerce, sub-

ject to the jurisdiction of the Commission, and such sales by the Applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) Applicants are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(5) The sales of natural gas by Applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity, and certificates therefor should be issued as hereinafter ordered and conditioned.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Certificates of public convenience and necessity be and the same are hereby issued, upon the terms and conditions of this order, authorizing the sales by the Applicants herein of natural gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary for such sales, all as hereinbefore described and as more fully described in the respective applications in this proceeding.

(B) The certificates granted in paragraph (A) above are not transferable and shall be effective only so long as Applicants continue the operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations, and orders of the Commission.

(C) The grant of the certificates issued in paragraph (A) above shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or Part 154 or Part 157 of the Commission's Regulations thereunder, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter intituted by or against the Applicants. Further, our action in this proceeding shall not foreclose or prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contracts herein involved.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

NATURAL GAS PIPELINE COMPANY OF AMERICA, DOCKET NO. CP62-135

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued April 10, 1962)

On November 29, 1961, as supplemented on January 15, 1962, Natural Gas Pipeline Company of America (Applicant) filed in Docket No. CP62-135 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of natural gas facilities in Will County, Illinois, to deliver and sell natural gas to Northern Illinois Gas Company (Northern Illinois) for resale and distribution in the Village of Minooka, Illinois, all as more fully set forth in the application, as supplemented.

Applicant seeks authorization to construct and operate a side tap connection on its authorized and existing main transmission pipeline, approximately 150 feet of 3-inch lateral pipeline extending from said tap to the facilities of Northern Illinois, and a meter station located at the terminus of the proposed lateral line, all within Will County, Illinois. Northern Illinois estimates the cost of the proposed facilities to be $11,710, which will be financed from funds on hand.

Northern Illinois has received a 50-year franchise from the Village of Minooka and a certificate of public convenience and necessity from the Illinois Commerce Commission to render the proposed distribution service. The subject service by Applicant to Northern Illinois will be rendered from presently authorized volumes of gas available to Northern Illinois.

The estimated market requirements for the Village of Minooka for the first and third years of service are as follows:

	First year	Third year
	Mcf	*Mcf*
Annual	20,200	27,800
Peak day	198	287

Pursuant to due notice, a public hearing was held in Washington, D. C., on March 27, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Natural Gas Pipeline Company of America, a Delaware corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 13, 1942, in Docket No. G–235 (3 FPC 830).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) The construction and operation of the proposed facilities and the proposed transportation and sale of natural gas by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(4) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(6) The proposed service should be rendered only from presently authorized volumes available to Northern Illinois from Applicant, and no increased volumetric obligation should be placed upon Natural for the proposed service.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Natural Gas Pipeline Company of America to construct and operate the proposed facilities and to sell natural gas to Northern Illinois Gas Company for resale and distribution in the Village of Minooka, Illinois, as hereinbefore described and as more fully described in the application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The proposed service shall be rendered only from presently authorized volumes available to Northern Illinois from Applicant, and no increased volumetric obligation shall be placed on Applicant for the proposed service.

(D) The facilities hereby authorized shall be constructed and placed in actual operation and the delivery of natural gas authorized in paragraph (A) above shall commence, as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act, within 12 months from the date on which this order issues.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

PACIFIC POWER & LIGHT COMPANY, DOCKET NO. E-7024

SUPPLEMENTAL ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTGAGE BONDS

(Issued April 11, 1962)

By order issued March 28, 1962, 27 FPC 617, in the above-entitled matter, the Commission authorized Pacific Power & Light Company (Applicant) to issue and sell at competitive bidding $35,000,000, principal amount of First Mortgage Bonds, due 1992, subject, among others, to the provisions set forth in paragraph (B) of that order, as follows:

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

Applicant on April 11, 1962, filed an amendment, pursuant to the requirements of the afore-mentioned Commission order, setting forth, among other things, that it proposes to accept as providing the lowest annual cost of money to it,

the bid of Halsey, Stuart & Co., Inc., to purchase the proposed issuance of $35,000,000, principal amount of Bonds, for the price of 100.02% of principal amount, with an interest rate of 4¾%.

The Commission finds:

(1) Applicant has satisfactorily complied with the requirements of paragraph (B) of the Commission's order issued March 28, 1962, in the above docket, and under the bid it proposes to accept for the Bonds, the price to be received by Applicant therefor and the interest rate thereof are reasonable.

(2) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The price to be received by Applicant for the proposed Bonds and the interest rate thereof under the bid referred to above are approved as reasonable.

(B) The proposed issuance and sale of Bonds referred to above, upon the terms and conditions and for the purposes specified in the application, as supplemented by the amendment referred to above, are authorized, subject only to the provisions of paragraphs (A), (C), (D), and (E) of the Commission's order issued March 28, 1962 in the above docket.

Commissioner Morgan *dissenting* stated: My objections to this issue, as expressed in my dissent to the order, have not been answered or satisfied and I therefore do not concur in this issue under the prevailing conditions.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Charles R. Ross.

PAUL J. FLY (OPERATOR), *ET AL.*, DOCKET NO. G–20207

ORDER ACCEPTING OFFER OF SETTLEMENT TERMINATING PROCEEDING AND PRESCRIBING REFUNDS

(Issued April 12, 1962)

On March 2, 1962, Paul J. Fly, (Operator), *et al.* (Fly), tendered an Offer of Settlement in the above-entitled proceeding pursuant to Section 1.18(e) of the Commission's Rules of Practice and Procedure, which offer was agreed to by its purchaser, Trunkline Gas Company (Trunkline).

In its Offer of Settlement, Fly proposes to reduce the 15¢ per Mcf rate suspended in the above entitled proceeding to 14¢ per Mcf and delete the flexible pricing provisions from the contracts. Fly requests that its 14¢ rate be permitted to become effective as of May 7, 1960, and agrees to refund the difference between the settlement rate of 14¢ per Mcf and the 15¢ per Mcf rate collected subject to refund.

In support of the offer, Fly cites the deletion of flexible pricing provisions and states that such provisions were important components of the original contracts. Fly also states that the settlement rates are below the level of prices recently negotiated in the area (Texas Railroad Commission District No. 2) and are in line with the price level announced in the Commission's Statement of General Policy No. 61–1.

The Commission finds:

(1) The proposed settlement of this rate proceeding on the basis described herein, as more fully set forth in the offer of settlement filed by Fly and Trunkline on March 2, 1962, is in the public interest and appropriate to carry out the provisions of the Natural Gas Act and should be approved and made effective as hereinafter ordered.

(2) Good cause exists for terminating the proceeding in Docket No. G–20207.

The Commission orders:

(A) The Offer of Settlement filed by Fly and Trunkline on March 2, 1962, is hereby approved in accordance with the provisions of this order.

(B) The amendments to Fly's gas purchase contracts tendered concurrently with the Offer of Settlement and executed by Trunkline and Fly are hereby accepted as Supplement No. 5 to Fly's FPC Gas Rate Schedules Nos. 1 and 2 effective as of May 7, 1960.

(C) Within 45 days from the date of issuance of this order, Fly shall refund to Trunkline the difference between the amounts collected from Trunkline and the rate agreed upon in the Offer of Settlement, together with simple interest at the rate of 7 percent per annum from the respective dates of receipt of said excess amounts by Fly to the date of refund. Fly shall bear all costs incidental to the making of such refunds.

(D) Within 60 days from the date of issuance of this order, Fly shall report to the Commission in writing and under oath the details of its calculations resulting in refunds ordered pursuant to paragraph (C) above, together with copies of releases from Trunkline with respect to such refunds.

(E) The proceedings in Docket No. G–20207 is hereby terminated.

(F) The acceptance of this Offer of Settlement is without prejudice to any findings or determinations that may be made in any proceedings which are presently being heard, or in any other proceedings now pending, or hereinafter instituted by or against Fly.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

ALABAMA POWER COMPANY, PROJECT NO. 2165

ORDER APPROVING EXHIBITS AND PRESCRIBING ANNUAL CHARGE

(Issued April 13, 1962)

Alabama Power Company, licensee for major Project No. 2165, pursuant to Article 39 of the license for the project, filed for Commission approval Exhibits J and K on September 16, 1959, and Exhibit F on September 17, 1959, November 25, 1959, and November 10, 1960, showing the location and the project boundary of the John Hollis Bankhead powerhouse site and the project boundary of the Lewis Smith Dam development.

The project is located on the Black Warrior River and on the Sipsey Fork of Black Warrior River, navigable waters of the United States, in Cullman, Walker, Winston, and Tuscaloosa Counties, Alabama, and affects United States Lock and Dam No. 17 and appurtenant lands, and lands of the United States within the William B. Bankhead National Forest.

On the basis of Exhibit K, it has been determined that the project occupies 2679 acres of lands of the United States within the William B. Bankhead National Forest, exclusive of those lands which may be used for transmission-line right-of-way.

The effect of approving the exhibits, among others, will be to fix the annual charge to be paid under the license for the project for recompensing the United States for the use, occupancy, and enjoyment of its lands within the William B. Bankhead National Forest, exclusive of those lands which may be used for transmission-line right-of-way.

The Chief, Forest Service, acting for the Secretary of Agriculture, who has supervision over the William B. Bankhead National Forest, has informed the Commission that approval of Exhibit K will not interfere or be inconsistent with the purpose for which the William B. Bankhead National Forest was acquired and that adequate protection and utilization of the national forest is assured by the conditions already in effect under the license for the project.

The Commission finds:

(1) The following exhibits conform to the Commission's rules and regulations and should be approved as part of the license for the project, it being unnecessary to approve Exhibit F as part of the license for the project:

Exhibit J: (FPC No. 2165–48) John Hollis Bankhead Development—Project Area Map; *Exhibit K:* (FPC No. 2165–49) John Hollis Bankhead Development—Project Area Map; and *Exhibit K:* (FPC No. 2165–50 through –69) Lewis Smith Reservoir—Project Area Map.

(2) The amount of the annual charge to be paid under the license for the purpose of recompensing the United States for the use, occupancy, and enjoyment of its lands within the William B. Bankhead National Forest, exclusive of those lands which may be used for transmission-line right-of-way, is reasonable as hereinafter fixed and specified.

The Commission orders:

(A) The above-described exhibits are approved as part of the license for the project.

(B) Article 42 of the license, as amended, is further amended by changing Paragraph (ii) thereof to read as follows:

(ii) Effective September 1, 1957, for the purpose of recompensing the United States for the use, occupancy, and enjoyment of its lands within the William B. Bankhead National Forest, exclusive of those lands which may be used for transmission-line right-of-way, $5,358.00; and

(C) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313(a) of the Federal Power Act and failure to file such an application shall constitute acceptance of this order. In acknowledgment of the acceptance of this order, it shall be signed for the Licensee and returned to the Commission within 60 days from the date of its issuance.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

PAN AMERICAN PETROLEUM CORPORATION, DOCKET NO. G–15641; PAN AMERICAN PETROLEUM CORPORATION (OPERATOR), *ET AL.*, DOCKET NOS. G–15650 AND G–15780

ORDER GRANTING EXTENSION OF TIME

(Issued April 13, 1962)

By its order issued March 5, 1962, in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, the Commission disposed of more than 400 proceedings, including those

above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. With respect to the above-listed dockets, ordering paragraph (A) of the March 5 order directed Pan American Petroleum Corporation (Pan American) to refund tax-reimbursement amounts collected from its direct customer United Fuel Gas Company (United Fuel), an intervener in those dockets. Ordering paragraph (C) of that order directed that within 90 days from the date of issuance thereof, Pan American report to the Commission the details of its refund calculations and submit a copy of a release from United Fuel with respect to the required refunds.

On March 15, 1962, Pan American filed in six dockets, including the three dockets listed above, an application for rehearing of the March 5 order. By an order issued concurrently herewith, the Commission is denying said application for rehearing.

In addition to its application for rehearing, Pan American, on March 15, 1962, filed a motion seeking to stay the effectiveness of ordering paragraphs (A) and (C) of the March 5 order until conclusion of judicial review of that order and of the Commission's prior order of August 30, 1961,[1] or in the alternative, to extend the time for compliance with said ordering paragraphs (A) and (C) until 90 days after conclusion of such judicial review. Pan American has heretofore filed petitions for review of both the August 30, 1961, and March 5, 1962, orders in the United States Court of Appeals for the District of Columbia Circuit.

The Commission is satisfied that the public interest will not be injured by the postponement of refunds pending conclusion of judicial review and that such postponement would obviate a great deal of needless effort in the event the Commission's March 5 order is reversed. Accordingly, we are disposed to grant Pan American's request for an extension of time within which to comply with the March 5 order. However, inasmuch as the 90-day period allowed by ordering paragraph (C) of the March 5 order was solely for the purpose of giving Pan American time to seek judicial review, there is no reason to grant a similar period of grace after that review has been obtained. We believe that the purposes for which this extension is granted will be adequately served if the deadline for compliance is postponed until the 30th day after conclusion of court review in the above dockets. Moreover, it is reasonable that the extension herein granted be conditioned upon the payment by Pan American to United Fuel of interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after the issuance of the order of March 5.

The Commission finds:

(1) There is good cause for extending the time within which Pan American must comply with the requirements of ordering paragraphs (A) and (C) of our order of March 5, 1962, for a period ending 30 days after conclusion of judicial review of that order, and of the Commission's prior order of August 30, 1961, in the instant dockets.

(2) It is just and reasonable and in the public interest that Pan American be required to pay United Fuel interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after the issuance of our March 5 order.

The Commission orders:

(A) The time within which Pan American must comply with ordering paragraphs (A) and (C) of the Commission's order of March 5, 1962, is extended

[1] The August 30, 1961, order reopened all of the Louisiana gathering tax proceedings and set the stage for final disposition of those proceedings on March 5, 1962.

for a period ending 30 days after conclusion of judicial review of the Commission's orders of August 30, 1961, and March 5, 1962, in the instant dockets.

(B) Pan American shall pay United Fuel interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the March 5, 1962, order.

(C) The time within which United Fuel must comply with ordering paragraphs (B) and (D) of the March 5, 1962, order is extended for a period ending 60 days after conclusion of judicial review of the Commission's August 30, 1961, and March 5, 1962, orders in the instant dockets.

(D) In the event that Pan American's pending petitions for review are dismissed on grounds of prematurity and that no additional petitions for review are filed within the time limit prescribed by Section 19(b) of the Natural Gas Act, the preceeding paragraphs (A) through (C) hereof shall be deemed inoperative and of no effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

PAN AMERICAN PETROLEUM CORPORATION, DOCKET NOS. G–15641, G–16065, AND G–16066; PAN AMERICAN PETROLEUM CORPORATION (OPERATOR), *ET AL.*, DOCKET NOS. G–15650, G–15780, AND G–16067

ORDER DENYING APPLICATION FOR REHEARING

(Issued April 13, 1962)

On March 15, 1962, Pan American Petroleum Corporation (Pan American) filed application in the above dockets for rehearing of the Commission's omnibus order of March 5, 1962 in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.* By that order we disposed of more than 400 proceedings, including those above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. In Docket Nos. G–15641, G–15650, and G–15780, the March 5 order directed Pan American to refund tax-reimbursement amounts collected from its direct customer United Fuel Gas Company (United Fuel), an intervenor in those dockets. In Docket Nos. G–16065, G–16066, and G–16067, the Commission vacated its order of August 30, 1961, by which all proceedings had been reopened, and thereby reinstated its May 29, 1961, order absolving Pan American from the duty to make refunds. With respect to the latter three dockets, Pan American was not aggrieved by the Commission's order and therefore has not standing to seek rehearing.[1]

The principal contentions advanced by Pan American in support of its application are as follows: (a) that under the terms of Section 19 of the Natural Gas Act the Commission lacked jurisdiction to reconsider or disturb the finality of the May 29 order; (b) that Pan American was improperly deprived of the trial-type hearing[2] allegedly required by the Administrative Procedure Act, the Natural Gas Act, and the Commission's regulations; and (c) that the Com-

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[1] Section 19(a) of the Natural Gas Act.

[2] Specifically, Pan American claimed the right to introduce evidence in its behalf (presumably through oral testimony), object to evidence sought to be introduced against it, cross-examine adverse witnesses, and introduce rebuttal evidence. For convenience we shall refer to this bundle of procedural incidents as a "trial-type hearing," borrowing a term coined by Professor K. C. Davis. See 1 Davis, *Administrative Law Treatise* 410 (1958).

mission's order in Docket Nos. G–15641, G–15650, and G–15780 was neither supported by the record nor based upon adequate findings of fact.

The question of the finality of the May 29 order was discussed at length in the order of March 5, and the application raises no objections not previously considered by the Commission.

We cannot agree that the March 5 order was vitiated by the absence of a trial-type hearing. As we explained in our August 30 order, the issues raised in these proceedings were primary, if not exclusively, issues of law, and did not require the adjudication of any disputed factual questions. The procedure we established in that order gave all parties ample opportunity to be heard. Specifically, each party was invited to file a statement of position and to tender in writing any evidence it might deem pertinent. In addition, it was permitted to file a reply to the statements of position filed by other parties. Had it appeared from these submissions that there was a dispute as to any factual matter which might materially bear upon our decision, the Commission might then have convened an oral evidentiary hearing to resolve that dispute. Since the Commission was not in fact called upon to resolve any conflict of testimony, if indeed any such conflict existed, there was no necessity to deal with the 400 or more pending proceedings through the cumbersome and time-consuming mechanism of a trial-type hearing.

In support of a contrary view, Pan American cites Sections 5 and 7 of the Administrative Procedure Act,[3] Section 4(e) of the Natural Gas Act, and Section 1.20 of the Commission's Rules of Practice and Procedure. However, the cited provisions of the Administrative Procedure Act do not apply except in cases of "adjudication required by statute to be determined on the record after opportunity for an agency hearing * * *." To ascertain whether such an adjudication is required in the instant case one must look to Section 4(e) of the Natural Gas Act. Assuming that Section 4(e) would require a "hearing" in the case of a rate filing based solely upon a tax increase, it says nothing at all about a determination "on the record." The term "hearing" is a flexible and comprehensive term which applies to argument-type as well as trial-type proceedings. We are convinced that under present circumstances the procedure adopted by the Commission satisfied the requirements of Section 4(e) and that since that Section did not dictate a trial-type hearing, the specifications of the Administrative Procedure Act were not called into play. Finally, it is plain that Section 1.20 of our Rules of Practice and Procedure was intended to govern only "hearings for the purpose of taking evidence" [4] and not to preclude an argument-type procedure such as the one herein followed.

It is important to note that Pan American has not suggested what additional evidence, if any, it would have sought to introduce or elicit had it been given a chance to examine or cross-examine witnesses. Moreover, it has not attempted to explain in what respect the procedure we adopted impeded it from bringing all relevant facts to our attention or from challenging the facts alleged or evidence adduced by other parties. After careful study of Pan American's application for rehearing, together with its statement of position and other documents of record filed prior to the March 5 order, the nearest approximation we find to a disputed issue of fact is the question whether Pan American owed United Fuel a contractual duty to protest the Louisiana tax. This question, however, was entirely immaterial, for the Commission's decision to require refunds was not based in any way upon contractual considerations. On the

[3] 5 U.S.C. §§ 1004, 1006.

[4] See Section 1.20(a) of Federal Power Commission Rules of Practice and Procedure.

contrary, we expressedly declared in our March 5 order that "having decided on other grounds to order refunds, we deem it unnecessary to pass upon the *Mobile* question or to construe the tax reimbursement provisions of the subject contracts."

Finally, we see no merit in the contention that the March 5 order was not supported by adequate evidence in the record or by appropriate findings of fact. The facts upon which we relied in reaching our conclusion to order refunds, and the manner in which those facts were evaluated, were fully set forth in the body of the March 5 order. The only respect in which the Commission is specifically alleged by Pan American to have defied the record is in ignoring "evidence which clearly shows the course of conduct upon which United Fuel and Pan American had agreed" and refusing "to give effect to the tax payment sharing arrangement agreed by United Fuel and Pan American."[5] Although, as noted earlier, the terms of the contract between Pan American and United Fuel were irrevelant to the Commission's decision, a word should perhaps be said about the "course of conduct" from which Pan American apparently seeks to infer that United Fuel acquiesced in its failure to pay the tax under protest. There is no basis whatever in the record for inferring such acquiescence. A series of appendices attached to Pan American's October 2, 1961, application for rehearing of our August 30 order discloses the following facts: that by letter of September 11, 1958, United Fuel reminded Pan American of its obligation under the Commission's Order No. 206 to repay tax reimbursement amounts if the Louisiana tax were held invalid, and advised it to pay the tax under protest if it wished to protect its own position; that Pan American subsequently deleted from the back of United Fuel's tax reimbursement check, dated February 4, 1959, a restrictive endorsement providing that repayment would be made if the tax were invalidated; that by letter dated February 11, 1959, to United Fuel, Pan American denied any contractual obligation to refund tax reimbursement amounts; and that by letter of February 13, 1959, United Fuel agreed to redraw its February 4 check without the original restrictive endorsement, upon the understanding that such action would not prejudice the rights of either party. We fail to see how this chain of communications can possibly be construed as an acquiescence by United Fuel in the position urged by Pan American.

The Commission finds:

Pan American's application for rehearing of the Commission's order of March 5, 1962, should be denied.

The Commission orders:

Pan American's application for rehearing of the Commission's order of March 5, 1962, is hereby denied.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

UNITED GAS PIPE LINE COMPANY, DOCKET NO. CP62-161

ORDER GRANTING PETITION FOR DECLARATORY ORDER AND PROVIDING FOR HEARING

(Issued April 13, 1962)

On January 8, 1962, United Gas Pipe Line Company (United) filed a Petition for Declaratory Order under Section 16 of the Natural Gas Act and Section

[5] Application for Rehearing, at p. 11.

1.7(c) of the Regulations thereunder, requesting that the Commission determine a question of jurisdiction regarding certain gas sales by United in the Jackson District of eastern Louisiana.

The facts set forth in the petition are briefly as follows: On November 2, 1954, the Commission issued Opinion No. 277,[1] determining, among other things, its jurisdiction over sales by United in the area in question. The Commission found that its jurisdiction as set forth in the Natural Gas Act extended to United's Jackson District, including that part of Louisiana north of Lake Ponchatrain and east of the Mississippi River (the so-called Florida parishes).

On June 8, 1961, the Louisiana Public Service Commission (Louisiana Commission) issued an order directing United to show cause why it should not charge its intrastate New Orleans zone rates for gas sold in the Louisiana parishes and particularly that sold to certain Louisiana towns within the Jackson District.[2] Further, the Louisiana Commission indicated its intention to exercise regulatory jurisdiction over sales by United within the Florida Parishes and to the towns specified unless United could show cause why such order should not be issued. United filed exceptions to the order of June 8, 1961, and hearings were instituted by the Louisiana Commission.

On February 21, 1962, United obtained a temporary restraining order against enforcement of the Louisiana State Public Service Commission's order of June 3, 1961. United's petition states that under the present circumstances, upon conclusion of the matter now before the Louisiana Commission, United might "be faced with conflicting orders of the two regulatory agencies and obviously it could not, at the same time, comply with both." This Commission, in reply to a letter request of the Louisiana Commission that the question of jurisdiction be re-examined, stated that formal proceedings were the appropriate method for disposing of the matter, and could be initiated by a petition for declaratory order or by United's filing a notice of cancellation of the service agreements covering the sales in question. Thereafter, United filed the petition presently under consideration.

The Commission finds:

Good cause exists for granting United's Petition for Declaratory Order and for setting for hearing the question of jurisdiction over the sales of natural gas by United to the aforementioned communities in that part of Louisiana situated within United's Jackson District called the Florida Parishes.

The Commission orders:

(A) Pursuant to the authority contained in the Natural Gas Act, a hearing shall be held May 7, 1962, in a hearing room of the Federal Power Commission, 441 G Street NW., Washington 25, D.C., at 10:00 a.m. EDT, regarding the issues as set forth and specified above, with United introducing at the outset of the hearing such evidence as may be necessary for a decision of the Commission in the matters indicated, and with subsequent opportunity for the presentation of such additional evidence by the parties as may be required at that time.

(B) Petitions to Intervene, and Notices of Intervention may be filed with the Federal Power Commission, Washington 25, D.C., in accordance with Sections 1.8 and 1.37(f) of the Commission's Rules of Practice and Procedure [18 CFR 1.8 and 1.37(f)], on or before April 30, 1962.

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[1] 13 FPC 398.

[2] The towns referred to are: Kentwood, Roseland, Greensburg, Montpelier, Amite, Independence, Natalbany, Hammond, Ponchatoula, Madisonville, Mandeville, Franklinton, Bogalusa, Covington, Abita Springs, Pearl River, Doyle, Livingston, Walker, Port Vincent, and Slidell.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

MIDWEST OIL CORPORATION (OPERATOR), *ET AL.*, DOCKET NOS. G–13774, G–16673, G–19760

ORDER AMENDING ORDER ACCEPTING OFFER OF SETTLEMENT AND TERMINATING PROCEEDINGS

(Issued April 16, 1962)

On February 23, 1962, Midwest Oil Corporation (Operator), *et al.* (Midwest Operator), tendered for filing an amendatory agreement executed by Differential Corporation (Differential). The amendatory agreement provides that gas attributable to Differential's non-operating interest, covered by Midwest Operator's FPC Gas Rate Schedule No. 11, be sold at a base rate of 14.0507¢ per Mcf (@ 15.025 psia exclusive of tax reimbursement) pursuant to Midwest Operator's offer of settlement accepted by Commission order issued July 28, 1960, 24 FPC 102. At the time of the said order Differential had not joined in said offer of settlement. The order, therefore, provided that with respect to Differential's interest in the sale the rate applicable to its gas should remain subject to refund in the above entitled proceedings.[1] However, with respect to the gas sold by all parties who did join in the said offer of settlement, the Commission's order of July 28, 1960 provided that upon compliance with certain filing and refund requirements, the proceedings in the above entitled dockets be terminated.

The subject filing, designated as Supplement No. 11 to Midwest Operator's FPC Gas Rate Schedule No. 11, consists of an amendatory agreement dated November 1, 1961, implementing the terms of Midwest Operator's offer of settlement. It is essentially the same as the agreement dated August 3, 1960,[2] executed by Midwest Operator and another signatory non-operator. Midwest Operator also submitted a release from Texas Eastern Transmission Corporation (Texas Eastern), the pipeline buyer, indicating it has received appropriate refunds due from Differential under the terms of Midwest Operator's offer of settlement. Midwest Operator requests withdrawal of Supplement No. 9 to its FPC Gas Rate Schedule No. 11 and also requests that the above entitled proceedings be terminated insofar as they pertain to the interest of Differential. Said Supplement No. 9 provides for the sale of gas at 14.2258¢ per Mcf subject to refund in Docket No. G–19760.

The Commission finds:

All parties in interest having now joined in the said offer of settlement and having fully complied with the refund and filing requirements of the Commission's order issued July 28, 1960, accepting such offer of settlement, it is appropriate and in the public interest to accept for filing the said Supplement No. 11 to Midwest's Operator's FPC Gas Rate Schedule No. 11, and to fully terminate these proceedings.

The Commission orders:

(A) Midwest Operator, having made satisfactory refunds and filings in compliance with the Commission's order issued July 28, 1960, is hereby discharged

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[1] At the time of Midwest's offer of settlement Differential's gas was being sold at the presently effective rate of 14.2558¢ Mcf pursuant to Supplement No. 9 subject to refund in Docket No. G–19760. Prior increased rates of 13.8456¢ per Mcf and 14.0507¢ per Mcf were subject to refund in Docket Nos. G–13774 and G–16673, respectively.

[2] Supplement No. 10 to Midwest's FPC Gas Rate Schedule No. 11.

from the refund obligations required by the several orders in these proceedings with respect to all parties in interest under its FPC Gas Rate Schedule No. 11.

(B) Supplement No. 11 to Midwest Operator's FPC Gas Rate Schedule No. 11, as tendered for filing on February 23, 1962, is hereby accepted for filing effective as of March 26, 1962, and Supplement No. 9 to Midwest Operator's FPC Gas Rate Schedule No. 11 is deemed to be withdrawn as to all parties in interest.

(C) The above-entitled proceedings are hereby terminated.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

WASHINGTON PUBLIC POWER SUPPLY SYSTEM, PROJECT NO. 2257

ORDER DENYING APPLICATION FOR EXTENSION OF PRELIMINARY PERMIT

(Issued April 16, 1962)

Application was filed on February 5, 1962, by Washington Public Power Supply System (WPPSS), of Kennewick, Washington, for a one-year extension of the preliminary permit issued for a period of two years for Project No. 2257, effective as of January 1, 1960.

The application states that if the extension sought is granted, WPPSS would undertake such studies as may be necessary to determine the project's feasibility for purposes of applying for a Commission license.

Under Article 9 of the permit, the permittee was required to submit at the close of each six-month period from the effective date of the permit, to the Commission's Regional Engineer at San Francisco, California, or to such other officer or agent as the Commission may designate, accurate statements of the work accomplished during that period and of the work contemplated under the permit for the ensuing period.

Our records show that three progress reports were filed prior to expiration of the permit on December 31, 1961. In the first such report, dated August 26, 1960, the permittee stated that because of the urgency of preparing material in connection with the public hearing on its application for the proposed Nez Perce Project No. 2273, it was unable to devote any effort to additional consideration of Project No. 2257, and, therefore, the progress during the first six-month period of the permit was insignificant. In the second such report, dated December 21, 1960, the permittee advised that it had retained a consulting engineering firm to proceed with the development of preliminary information on the proposed site and reservoir area to secure detailed topographic information from aerial mapping, when weather conditions on the Olympic Peninsula permit. And, in the third such report, dated July 13, 1961, the permittee advised there was no activity conducted during the six-month period previous thereto relating to the proposed project.

By letter dated February 12, 1962, the permittee advised that all of the investigation of the proposed project by its staff and consulting engineers was limited to office work.

The Commission finds:

In the circumstances recited herein, it would be inappropriate and incompatible with the provisions of the Federal Power Act to grant the application for extension.

The Commission orders:

The aforesaid application is denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

CITY OF SEWARD, ALASKA, PROJECT NO. 2171

ORDER ACCEPTING SURRENDER OF LICENSE (MAJOR)

(Issued April 17, 1962)

Application was filed December 13, 1960, by City of Seward, Alaska, licensee for proposed Project No. 2171, for surrender of its license for the project pursuant to Section 6 of the Federal Power Act.

The license for the proposed project—which was to have been located on Crescent and Carter Lakes on Kenai Peninsula in the Third Judicial Division, State of Alaska, affect lands of the United States within the Chugach National Forest, and consist of an earth fill dam at the outlet of Crescent Lake, a channel between Crescent and Carter Lakes, a penstock to a powerhouse containing a 3,500-kilowatt unit with provision for two additional units, a 69-kilovolt transmission line to Seward, and other appurtenances—was issued August 2, 1957, effective as of August 1, 1957, to City of Seward, Alaska, for a period of 50 years.

The only part of the previously proposed project constructed by the licensee is the 69-kilovolt transmission line between Seward (mile 7) and Falls Creek (mile 25.5). The licensee by letter dated October 14, 1960, informed the Commission that it had discontinued construction of the transmission line and that it had no plan at that time to commence construction of the project.

The transmission line between Seward and Falls Creek is presently being used as a 7.2/12.5-kilovolt distribution line, supplying rural customers along the Seward-Anchorage highway from Seward to approximately mile 25.5 of the highway at Falls Creek. The power for the line is supplied by the City of Seward's diesel plant exclusively, with no connection with any hydroelectric plant.

By letter dated November 13, 1961, the Forest Service, United States Department of Agriculture, informed the Commission that the national forest lands involved have been restored to a condition satisfactory to the Service and that a special-use permit has been issued by the Forest Service to the City of Seward for a right-of-way for a line across national forest lands from the Forest boundary at mile 5 of the Seward-Anchorage highway to approximately mile 25.5 at Falls Creek.

The licensee's copy of the license instrument has been returned.

The Commission finds:

(1) Public notice has been given of the filing of the application for surrender of the license and no protests thereon have been received.

(2) The line as presently operated is not part of a project within the meaning of Section 3(11) of the Federal Power Act and, therefore, is not within the licensing authority of the Commission.

(3) Acceptance of surrender of the license for the project is not inconsistent with the public interest.

The Commission orders:

Surrender of the license for proposed major Project No. 2171 is accepted.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TEXAS EASTERN TRANSMISSION CORPORATION, DOCKET NOS. G-12706 AND G-18841

ORDER FURTHER MODIFYING ORDER CONDITIONALLY APPROVING RATE SETTLEMENT AGREEMENT

(Issued April 17, 1962)

By order issued January 25, 1961, 25 FPC 172, in these proceedings, we approved the rate settlement agreement proposed by Texas Eastern Transmission Corporation (Texas Eastern) and ordered concomitant rate reductions and refunds to all of Texas Eastern's customers, except Ohio Valley Gas Corporation (Ohio Valley). With respect to Ohio Valley, we allowed Texas Eastern's rate increase proposals to remain in effect and ordered a hearing to be held concerning Ohio Valley's opposition to the rates proposed in the settlement agreement for Zone "C."

On February 14, 1962, Texas Eastern and Ohio Valley filed concurrent motions requesting the Commission to modify its order of January 25, 1961, as modified, so as to make said order applicable to Ohio Valley. In support of their motions, Texas Eastern and Ohio Valley state that Ohio Valley has now executed the settlement agreement approved by the Commission and Ohio Valley now wishes to withdraw its objections to said settlement.

The Commission finds:

It is reasonable and proper in the public interest to grant the motions filed by Texas Eastern and Ohio Valley on February 14, 1962, and to modify the said order of January 25, 1961, so as to make the settlement approved therein applicable to Ohio Valley as hereinafter ordered.

The Commission orders:

(A) The motions filed by Texas Eastern and Ohio Valley on February 14, 1962, in these proceedings, are hereby granted, and the order issued January 25, 1961, as modified by order issued February 21, 1961, and as further modified below is made applicable to Ohio Valley.

(B) The order issued herein on January 25, 1961, is hereby further modified so as to reflect the acquiescence of Ohio Valley in the settlement agreement approved by said order and Ohio Valley's withdrawal of its objections thereto. Paragraphs (H) and (I) of the said order are hereby deleted in their entirety, and Paragraph (2) of the findings and Paragraphs (C), (D) and (E) of said order are hereby amended by deleting therefrom the language contained therein, which excluded Ohio Valley from the provisions of those paragraphs.

(C) Texas Eastern shall forthwith make refunds to Ohio Valley in conformity with Paragraphs (D) and (E) of said order of all excess amounts collected to the date of such refunds with interest at the rate of 6 percent per annum. In addition, Texas Eastern shall report such refunds in the same manner prescribed in Paragraph (M) of the order issued January 25, 1961.

(D) In all other respects, the orders issued in these proceedings on January 25, 1961, and February 21, 1961, shall remain in full force and effect.

Commissioner Woodward *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

AREA RATE PROCEEDING, DOCKET NO. AR61–1; CLAUDE E. AIKMAN, *ET AL.*, DOCKET NO. G–18466, *ET AL.*; NORTH CENTRAL OIL CORPORATION (OPERATOR), *ET AL.*, DOCKET NO. CI60–435, *ET AL.*

ORDER DENYING MOTION TO TERMINATE PROCEEDING AND REJECTING WITHDRAWAL OF PROPOSED RATE INCREASE

(Issued April 18, 1962)

On January 19, 1962, Austral Oil Company Incorporated, Agent for Oil Participations Incorporated (Austral) filed a motion requesting its dismissal as a party to these proceedings and a notice of withdrawal of its proposed rate increase in Docket No. G–19540 which was consolidated herein by order of the Commission issued December 23, 1960.

Austral recites that the proposed increased rate under its FPC Gas Rate Schedule No. 5, which was suspended in Docket No. G–19540, represents its only sale of gas in interstate commerce from the Permian Basin area. Additionally, Austral states that because of pressure maintenance operations ordered by the Texas Railroad Commission deliveries of gas to El Paso Natural Gas Company (El Paso) ceased before the increased rate proposed in Docket No. G–19540 became effective and that it would be approximately twenty years before Austral resumes making gas sales from the Permian Basin area under this rate schedule.

By letter of February 16, 1962, the Secretary advised Austral that its requests for dismissal from the area rate proceeding would be deferred pending the filing of an application to abandon the sale to El Paso under its FPC Gas Rate Schedule No. 5.

By letter of March 19, 1962, Austral states that it does not propose to file an application to abandon the sale to El Paso under its FPC Gas Rate Schedule No. 5 and that the Commission should not consider Austral's request for withdrawal of its rate increase in Docket No. G–19540 except in conjunction with its motion for dismissal from these proceedings.

Since Austral has outstanding a certificate of public convenience and necessity for the sale of gas in interstate commerce for resale from the Permian Basin area and a rate schedule for such sale is on file with the Commission the lawfulness of the rate set forth in such rate schedule will be determined in the area proceeding. Accordingly, Austral's request to be dismissed from these consolidated proceedings must be denied and its related notice of withdrawal must be rejected.

The Commission orders:

Austral's motion to be dismissed as respondent in these proceedings is denied and its related notice of withdrawal is rejected.

ARKANSAS-LOUISIANA GAS COMPANY[1], DOCKET NO. G–17567; ILLINOIS POWER COMPANY, DOCKET NO. G–17984; ST. CHARLES GAS CORPORATION, DOCKET NO. G–18405; LACLEDE GAS COMPANY, COMPLAINANT v. MISSISSIPPI RIVER FUEL CORPORATION, DEFENDANT, DOCKET NO. G–17832

OPINION AND ORDER ALLOCATING CAPACITY AND REJECTING PROPOSED SETTLEMENT

(Issued April 18, 1962)*

Syllabus

1. Settlement agreement *rejected* since it is predicated on future contingencies and would, if approved, bind Commission to issue certificates for which application had not been filed, hearings held, or possible objections considered. P. 702.
2. Mississippi's proposed merger with its subsidiary, Transmission, appears in public interest because service and rates should not be affected by such an artificial corporate division; Commission notes that existing arrangement has not proved practical and will be abandoned, making unnecessary the institution of a Section 5(a) proceeding to determine possible discrimination between customers of Mississippi and Transmission. P. 702.
3. In light of present record Commission is of the opinion that it was not in the public interest to establish separate supplier of gas and impose high costs of new pipeline wholly on Laclede and Illinois Power . . . costs of pipeline extensions ordinarily being rolled-in so all customers bear new costs, consistent with Commission allocation principles. P. 703.
4. Holding Mississippi has not performed its obligations to its utility customers, Commission *orders* additional capacity be supplied such customers [from portion of gas now going to industrials], giving first consideration to needs of domestic and commercial users. P. 703.
5. Noting that Mississippi's resale customers' requirements include industrial sales, Commission finds no justification in the record for favoring such sales over Mississippi's direct industrial customers. P. 703.
6. Distinguishing firm and interruptible service, Commission holds that if utility has right to curtail service, customers receive and pay for interruptible service even if right of curtailment is not exercised . . . . Thus service to Mississippi's so-called firm customers is interruptible and must be considered as such when determining possible impairment. P. 705.
7. Mississippi's right to serve its industrials has been substantially retained when consideration is given nonfirm nature of the service, substantial capacity allocated industrials, and availability of gas from Transmission. P. 706.
8. While arrangement by which more expensive pipeline gas is sold to Laclede and Illinois Power is unsatisfactory, this is not a rate case and proper rates of Mississippi and Transmission should be left to later proceeding. P. 707.
9. Taking notice of the needs of four Mississippi customers who were not participants, Commission reserves allocation of gas for such customers for a reasonable time, pending application therefor. P. 707.

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[1] Formerly MidSouth Gas Company. When reference is made to Arkansas-Louisiana as successor to MidSouth, it will be termed Ark-La (MidSouth); when reference is made to Arkansas-Louisiana as a separate recipient of gas, it will be termed simply Ark-La.

*Designated Commission Opinion No. 355; initial decision appears on p. 713; supplemental decision on p. 748. Modified and rehearing denied by order issued June 15, 1962, 27 FPC 1257. Set aside with respect to reallocation of capacity between Mississippi's industrial customers and public utility customers, 320 F. 2d 711 (1963).

10. Mississippi required to file applications for certificates for authority to continue to serve such direct sales customers as it was not serving on effective date of its "Grandfather" certificate. P. 708.
11. Commission *issues* order allocating capacity on Mississippi's system pursuant to proceedings initiated under Sections 5(a) and 7(a) of the Natural Gas Act. P. 709.

John H. Hendren, Cleon Burt, Richmond C. Coburn, Justin R. Wolf and *Eugene Threadgill* for Mississippi River Fuel Corporation.

J. David Mann, Jr., William R. Ross, and *John E. Holtsinger, Jr.* for Laclede Gas Company.

Harry A. Poth, Jr., and *Richard M. Merriman* for Arkansas Louisiana Gas Company.

Robert S. Hunt, Q. P. Dorschel, and *John V. Gilhooly* for Illinois Power Company.

Norman J. Gundlach for American Brake Shoe Company, Obear Nester Glass Company, C. K. Williams & Company, and Lewin Mathes Company.

Willard W. Gatchell for Granite City Steel Company, Alton District Manufacturers' Association, American Zinc Company of Illinois, Olin Mathieson Chemical Corporation, and Pittsburgh Plate Glass Company.

Walter W. Gallagher and *George J. Meiburger* for Owens-Illinois Glass Company.

John J. Shanahan for City of St. Louis, Mo.

Norman A. Flaningam and *Christman B. Peper* for St. Charles Gas Corporation.

Ezkiel G. Stoddard, Oscar Cox, and *Phillip P. Brown* for Missouri Rolling Mill Corporation.

John P. Randolph and *Joseph H. Grand* for Missouri Natural Gas Company.

Charles J. Dougherty for Union Electric Company.

Robert W. Perdue for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

SWIDLER, *Chairman:*

These proceedings involve applications filed by Ark-La (MidSouth), Illinois Power Company and St. Charles Gas Corporation under Section 7(a) of the Natural Gas Act and a complaint filed by Laclede Gas Company under Section 5(a) of the Act against Mississippi River Fuel Corporation in order to obtain additional supplies of gas. Mississippi has capacity in excess of that presently available to its utility customer. The principal question at issue is whether this capacity or some of it, should be allocated to the utility customers, whereas it is now used to supply Mississippi's direct sale industrial customers. The examiner in both a first decision issued September 13, 1960, and in a second decision issued December 1, 1961, after reopening and further hearing, allocated all of this additional capacity to the utility customers except for 2,000 Mcf for industrial pilot lights. The proceedings are now before the Commission on the exceptions filed by a number of parties[2] to the second decision. There is also before us a settle-

[2] Ark-La (MidSouth), Owens Illinois Glass Company, Mississippi River Fuel, Missouri Natural Gas Co., Missouri Rolling Mill Corporation, joint exceptions by Obear-Nester Glass Company, American Brake Shoe Company and Lewin-Mathes Company, joint exceptions by Granite City Steel Company, Alton District Manufacturer's Association, American Steel Foundries, American Zinc Company of Illinois, Laclede Steel Company, National Lead Company, Olin Mathieson Chemical Corp., Pittsburgh Plate Glass Company, and C. K. Williams & Company, and the staff of this Commission.

ment agreement of Mississippi with six of its resale customers and the Public Service Commission of Missouri providing that Mississippi increase its deliveries to its resale customers upon receiving certain quantities of gas from its subsidiary Mississippi River Transmission Corporation (Transmission), which, in turn, proposes to purchase additional gas from Natural Gas Pipeline Company of America. For the reasons set forth below, we are rejecting the proposed settlement. We are in basic agreement with the examiner's allocation of Mississippi's excess capacity, although we differ in the amount of gas to be allocated to Mississippi's utility customers. We, therefore, find it necessary to consider the factual and legal problems involved and the proper allocation of Mississippi's excess capacity.

Mississippi, which began operations in 1929, has two parallel transmission lines, approximately 431 miles long extending from Perryville, Louisiana, where gas is delivered primarily by United Gas Pipe Line Company. One line terminates in Missouri and the other in Illinois. It also has a transmission line extending from Perryville to the Woodlawn Field in Texas. Mississippi has been serving Ark-La's (MidSouth) predecessors since 1929, but its principal sales take place in the vicinity of St. Louis, Missouri, and East St. Louis and Alton, Illinois.

After issuance of prior certificates, the Commission on September 2, 1952, issued an order authorizing Mississippi to construct and operate facilities designed to increase its capacity to 450,000 Mcf per day, 11 FPC 1219; on August 2, 1957, the Commission granted Mississippi a certificate authorizing an additional increase in capacity of 10,000 Mcf per day, 18 FPC 106. Because of increased system capacity achieved by operating improvements, this last order increased the capacity to 515,000 Mcf, and a further order of October 14, 1958, 20 FPC 517, brought the capacity to 522,000 Mcf per day. In the present proceeding Mississippi admits a daily system capacity of 524,000 Mcf, and the examiner has found a sustained dependable delivery capacity of 534,000 Mcf, of which not less than 447,303 Mcf is deliverable in the St. Louis area. Actually the record shows that the system has been able to deliver even larger quantities for short periods. For instance, the system delivered 555,785 Mcf on the peak day of the 1958–1959 heating season.

Mississippi sells gas for resale to a number of customers including utilities and towns. As set forth in the tariff the stated or firm demands of these resale customers is 468,585 Mcf, of which Laclede Gas Co. takes 330,000 Mcf and Illinois Power Co. 57,202 Mcf. Mississippi also sells gas to a number of direct industrial customers principally in the St. Louis area. It considers part of its industrial sales as "firm" sales, even though the contracts provide for curtailment, and part of these sales as interruptible. The examiner found that in the year 1960 Mississippi earned some $6½ million more than its own allocated cost of service to those industrial sales.

Because it failed to obtain the additional gas to which it believes it is entitled Laclede, Mississippi's largest customer, filed its complaint under section 5(a) seeking a determination of Mississippi's present capacity and relief from certain provisions of Mississippi's tariff. Ark-La (MidSouth), Illinois Power and St. Charles, existing utility customers of Mississippi, also needing additional supplies of gas, applied under section 7(a). Laclede's complaint and the 7(a) applications were consolidated and a hearing was held.

In his first decision, issued September 13, 1960, the examiner ordered Mississippi to increase the stated demands of its present utility customers by certain specified amounts that would, roughly, allocate Mississippi's capacity over the

present stated demands to its utility customers; he required Mississippi to file certain changes in its rate schedules providing for the allocation of excess gas to its general service buyers and for reduced overrun penalties; and he required the filing of applications for certificates for facilities, which, he said, Mississippi had not received authority to construct.

On January 10, 1961, Mississippi filed a petition for an order reopening the proceedings on the ground that the utilities' gas supply situation had changed materially because of Transmission's pipeline to the St. Louis area authorized by the Commission on November 29, 1960, 24 FPC 1020, because of additional capacity of Laclede and because of the satisfaction of the application of Ark-La (MidSouth). On March 27, 1961, the Commission ordered that the proceedings be reopened for taking additional evidence on the needs of the utility customers, on the changes, if any, required in Mississippi's tariff pertaining to the establishment of priorities of service between direct and resale customers, and on the supplies of gas available to Mississippi's various customers. Hearings were held on seven days commencing May 31, 1961, and ending on July 26, 1961. The examiner issued his second decision on December 1, 1961.

Apart from his charges that Mississippi had installed facilities without authorization,[3] the examiner strongly criticized it for failing to increase the supplies of gas available to its utility customers while retaining its profitable service to its industrial customers. He noted that Transmission is now authorized to deliver effective December 1, 1961, 63,750 Mcf per day to Laclede and 11,250 Mcf per day to Illinois Power, but Transmission's price is 46.3 cents per Mcf on the basis of a 75 percent load factor in contrast to Mississippi's own price of 31.7 cents per Mcf at a 60 percent load factor. He did not consider Transmission's sale a satisfactory solution to the gas supply problem particularly because of the higher costs, and pointed out that the evidence showed that Mississippi had refused to supply additional gas on the basis of rolled-in costs and had offered the "new subsidiary or nothing."

The examiner did not agree with Mississippi's contentions with respect to Laclede's Lange storage field. Mississippi had argued that the St. Peter formation in the field was not being used to the maximum extent possible and that the Roubidoux formation will be able to supply greater volumes of gas on a peak day. The examiner thought that Laclede's most recent first hand evidence was more persuasive than Mississippi's.

The examiner's solution to the gas supply question, as in his previous decision, was to allocate Mississippi's capacity available above the stated demands of its existing utility customers. From the daily capacity of Mississippi's system of 534,000 Mcf as found by him, he subtracted the present stated demands of the utility customers of 468,795 Mcf[4] and an additional 2,000 Mcf for industrial pilot light service leaving a balance of 63,205 Mcf which he allocated to the utility customers generally in proportion to their stated demands as set forth in the table at page 704 of this opinion. As in his first decision, he generally increased the stated demands of the corporate utility customers. For instance, he gave an additional 45,500 Mcf to Laclede raising its stated demand to 375,500 Mcf per day and 7,989 Mcf to Illinois Power raising its stated demand to 65,191 Mcf per day. As for the towns south of the St. Louis area,[5] he left their stated demands unchanged. Because Union Electric Company, Dupo, PUC Crossett and Ashley County were not parties, he reserved their volumes for six months pending the filing of applications by them.

[3] This matter was the subject of the Commission's order of February 8, 1962, 27 FPC 330, and need not be further discussed here.

[4] Including 640 Mcf for City of Red Bud, Docket No. G–16504, 25 FPC 987.

[5] Chester, Hazen, Altheimer, Augusta, Des Arc, Red Bud.

In connection with his allocation the examiner pointed out that Transmission is merely Mississippi's agent, that Transmission has a present capacity of 140,000 Mcf per day, of which Laclede and Illinois Power have contracted to purchase 75,000 Mcf, that its capacity could be increased to 200,000 Mcf per day, and that Transmission's gas supplies can be made available to all of Mississippi's customers if they are willing to pay the price. We may note that Transmission's pipeline is an 18-inch diameter line which connects with the system of Trunkline Gas Co. in Clay County, north of Johnsonville, Illinois, and extends approximately 94 miles westerly to the west bank of the Mississippi River in north St. Louis County. In so doing it makes deliveries both to Illinois Power and Laclede. As the examiner points out, we authorized an interconnection between Transmission and the main line of Natural Gas Pipeline Company of America in Clinton County, Illinois[6] and an interconnection between Mississippi and Transmission in Madison County, Illinois.[7] In the latter order we recited:

> The purpose of the authorization is to permit Fuel and Transmission to make deliveries of natural gas to each other when such deliveries can assist in their respective system operations and can be made without curtailment or interruption of service to the markets of the party making such deliveries. Under the exchange agreement, the party receiving deliveries thereunder is obligated to return a like quantity of gas to the other party. The exchange of gas will provide added flexibility of operation and continuity of service for both Fuel and Transmission.

As in his prior decision the examiner required Mississippi to file modifications of its rate schedules. One is to provide that any buyer whose gas requirements have not been met by Mississippi will remain a general service buyer under the F–1 Rate Schedule even if it obtains gas elsewhere. Another change is to be a revision of Mississippi's F–1 Rate Schedule to provide for the apportionment of excess gas equitably among the remaining F–1 buyers. A third amendment would reduce the penalty on overrun gas which had formerly extended to $10 per Mcf. The new penalty would be limited to $5 per Mcf for takes in excess of 3 percent of the stated demand.

The examiner's decision was followed by the exceptions which are listed in footnote 2 and which will be discussed below.

The settlement agreement was filed on March 27, 1962, by Mississippi under covering letter of the same date.[8] In addition to Mississippi it was signed by Laclede, Illinois Power, St. Charles Gas Corp., Ark-La (MidSouth), Union Electric Company, Missouri Natural Gas Company and the Public Service Commission of Missouri but not by any other customers of Mississippi. The crux of the settlement is the purchase by Mississippi of additional volumes of gas from Transmission and resale of the gas to its customers. This would be done in two steps—35,000 Mcf per day effective December 1, 1962, and an additional 30,000 Mcf per day effective December 1, 1963. As a result of these proposed purchases Mississippi would increase the stated demands of many of its resale customers in two steps on the same dates. In the agreement Mississippi reserved 70,000 Mcf of gas per day for sales to its direct industrial customers. Deliveries to

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[6] *Natural Gas Pipeline Company of America*, 26 FPC 543, Docket No. CP61–339, September 26, 1961.

[7] *Mississippi River Fuel Corporation*, 26 FPC 545, Docket No. CP61–341, September 26, 1961.

[8] This followed a similar settlement proposal filed March 6, 1962, by Mississippi and a conference held on March 26, 1962, at the Federal Power Commission but without participation by the Commission's staff except to call the meeting to order and state the staff's position.

these customers would not be curtailed below this amount except when necessary to serve the stated demands of the utility customers and to meet extraordinary conditions affecting the operations of the utility customers or Mississippi. Excess gas from Transmission would be made available by Mississippi to its utility customers.

The proposed agreement specifically makes the increased stated demands given Mississippi's utility customers contingent upon the sale of gas from Natural to Transmission including the requisite certificate authorization, acceptance of the certificate, installation of the facilities and actual availability of the gas. Thus the agreement is predicated on future contingencies and would, if approved, bind us to issue certificates of public convenience and necessity for which applications have not been filed, much less hearings held or possible objections considered. This would, of course, be contrary to Section 7(c) of the Natural Gas Act providing for reasonable notice and hearing in certificate cases.

In the covering letter to the proposed settlement agreement, Mississippi stated that its board of directors had voted to recommend to its stockholders a proposal that it merge with Transmission. It stated further that with the consummation of the merger, there would necessarily be a simplification of certain of its proposed rate schedules and it would make appropriate rate filings in that regard. Such a merger appears to be in the public interest because service and rates should not be affected by such an artificial corporate division. We are happy to see that the existing arrangement, which has not been proved to be practical, will be abandoned. This will make it unnecessary for the Commission to institute a proceeding under Section 5(a) to determine whether there is any discrimination between the customers of Mississippi and the customers of Transmission.

Turning to the present record the principal issue then before us is whether Mississippi's capacity, in excess of the stated demands of its utility customers should be allocated to these customers. Under the Natural Gas Act the questions are whether under Section 5(a) of the Act "any rate, charge, or classification" or any "rule, regulation, practice or contract" of Mississippi is "unjust, unreasonable, unduly discriminatory, or preferential" and whether under section 7(a) it is "necessary or desirable in the public interest" to direct Mississippi to sell additional natural gas to the utility customers. In addition, under section 16, we have "power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules and regulations as [we] may find necessary or appropriate to carry out the provisions of [the] Act."

The needs of some of Mississippi's utility customers for additional supplies of gas are shown as follows: [*]

Company	Peak day requirements, 1961–62	Supply (Mcf)		Balance needed
		Present stated demand from Mississippi	Estimate from other sources	
	Mcf			*Mcf*
Laclede	690,000	330,000	[1] 315,000	45,000
Illinois Power	111,000	57,202	[2] 53,798	0
Ark-La (MidSouth)	31,000	26,140	0	4,860
St. Charles	4,840	2,360	852	1,628
Missouri Natural	33,700	24,000	0	9,700

[1] Laclede receives 63,750 Mcf from Transmission.
[2] Illinois Power receives 11,250 Mcf from Transmission.

[*] Volumes are at 14.9 psia 60° F.

The record shows that Mississippi has not met the demands of its utility customers, and they have waiting lists of consumers desiring service. Laclede, whose contract with Mississippi is in terms for its full requirements, has not been granted an increase in its stated demand by Mississippi since 1955.

Meanwhile, Mississippi has been serving and has continued to serve its direct industrial customers. In the thirteen heating seasons from 1948–49 to 1960–61 the peak days of the so-called firm industrial customers have not varied greatly. The least demand was 58,710 Mcf in the last year and the greatest was 71,717 Mcf in the year 1959–60. Effective April 1, 1960, Mississippi's contractual obligations to its direct industrial customers were increased from a total of some 82,000 Mcf per day to over 98,000 Mcf per day.

While Mississippi continued to serve its industrial customers, the record shows that it would not extend additional service to its utility customers except through Transmission at the high costs of a new pipeline. As noted above, the Commission authorized the Transmission project,[10] but in the light of the present record we are of the opinion that it was not in the public interest to establish this separate supplier of gas and to impose the high costs of the new pipeline wholly on Laclede and Illinois Power. Ordinarily, the costs of pipeline extensions are "rolled-in" so that all customers bear the new costs consistent with the principles of cost allocation employed by the Commission. However, this proceeding is not a rate case[11] and we are in no position to consider the combined costs of Mississippi and Transmission.

On the basis of the record and within the scope of the proceeding we agree with the examiner that a remedy is required. Mississippi has retained and extended its service to its industrials including those served under contracts which it claims are firm but which are, in effect, interruptible while its utility customers have been greatly restricted except for service through Transmission. Mississippi, in effect, has not performed its utility obligation to its utility customers including the domestic and commercial consumers served by them. As said in *People ex rel. New York Gas Company* v. *McCall*, 245 U.S. 345, "Corporations which devote their property to a public use may not pick and choose, serving only the portions of the territory covered by their franchises which it is presently profitable for them to serve. . . ." We are properly concerned with the end use of this gas. *F.P.C.* v. *Transcontinental Gas Corp.*, 265 U.S. 1. In our opinion, under the circumstances here presented, its "practice or contract" is "unduly discriminatory or preferential" under section 5(a); it is "necessary or desirable in the public interest" under section 7(a) that Mississippi supply additional capacity to its utility customers. In this regard, Mississippi must give first consideration to the requirements of its utility customers to meet the needs of domestic and commercial users of natural gas. See *Panhandle Eastern Pipe Line Co.*, 6 FPC 196 (1947); 7 FPC 984 (1948); 9 FPC 1330 (1950); 10 FPC 328 (1951). Compare *Panhandle Eastern Pipe Line Co.* v. *FPC*, 232 F. 2d 467. (C.A. 3). In the method of allocation we adopt we do so.

The examiner's allocation of 63,205 Mcf, however, fails to take into account an important element: the requirements of the resale customers include industrial sales. There is no justification in the record for favoring the industrial customers of the utilities over Mississippi's direct industrial customers. The staff advocates an allocation of Mississippi's capacity that would appear to avoid this difficulty (see Exhibit 101).

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[10] *Trunkline Gas Co., et al.*, 24 FPC 1020 (November 29, 1960).

[11] Laclede's complaint was brought under section 5(a), but cost and rate levels are outside the scope of this proceeding.

The staff's method, we think properly, takes into account the industrial requirements of the utility customers. The staff witness used as his basis the data obtained by circulating a questionnaire to Mississippi's customers, direct and resale. He divided the peak day requirements of each resale customer into requirements for firm industrial sales and requirements for other sales. He then proceeded to allocate Mississippi's capacity first to the resale customers for non-industrial use and then allocated the remaining capacity to industrial users served both directly by Mississippi and upon resale by Mississippi's customers. To do this he determined the non-industrial requirements to be supplied by Mississippi by subtracting from total non-industrial requirements the requirements to be supplied by other sources of supply.[12] He determined the industrial requirements direct and resale to be supplied by Mississippi by deducting the non-industrial requirements from present system capacity and allocating the remaining capacity to Mississippi's resale customers and to Mississippi's direct sale customers in proportion to their industrial requirements. He added each customer's non-industrial requirements to its portion of the firm industrial allocation to obtain a theoretical stated demand which he adjusted so as to give the resale customers at least their existing stated demands. His results were as follows compared with the examiner's conclusions, the present stated demands, and the capacity of the system (at 14.9 psia):

	System capacity	Present stated demand	Examiner's allocations	Staff allocations
St. Louis Area	*Mcf*	*Mcf*	*Mcf*	*Mcf*
Laclede		330,000	375,500	339,245
Illinois Power		57,202	[1] 65,191	[3] 56,740
Union Electric		10,000	[3] 11,900	13,772
St. Charles		2,360	[4] 3,259	3,229
Dupo		675	[2] 975	775
Industrials		0	2,000	20,468
Total	447,303	400,237	458,825	434,229
Crossett Compressor Station to St. Louis				
Missouri Natural		24,000	28,000	33,525
MidSouth (Now Ark-La)		26,140	27,757	31,000
Ark-La		9,500	9,500	9,500
Chester		1,068	1,068	[5] 641
Hazen		456	456	559
Altheimer		350	350	350
Augusta		915	915	915
Des Arc		415	415	415
Fort Smith Gas Corp		2,700	2,700	2,700
Red Bud		430	640	641
Direct industrials		0	0	4,525
Total	71,697	65,974	71,801	84,771
Total North of Crossett	519,000	466,211	530,626	519,000
South of Crossett				
Public Util. (Crossett)		2,000	[3] 2,750	
Nat. Gas Improvement Dist. (Ashley Co)		374	[3] 624	
Total	15,000	2,374	3,374	
Total system	534,000	468,585	534,000	

[1] Effective November 1, 1963.
[2] Reserved pending application.
[3] Staff concedes an increase to the present stated demand of 57,202 Mcf.
[4] Effective November 1, 1962.
[5] Staff concedes an increase to the present stated demand of 1,068.

[12] Peak shaving, underground storage, and purchases from Transmission.

The staff's method is reasonable and we shall adopt it here in slightly modified form as shown in Appendix A to this opinion. With respect to the area south of the Crossett Compressor station, there is more than enough capacity available. We shall, therefore, adopt the examiner's allocation of 2,750 Mcf to Public Util. (Crossett) and 624 Mcf to Ashley County based upon the questionnaire. However, we agree with him that the gas allocated to these two customers and to Dupo and Union should be held in reserve six months pending their application under section 7(a).

Mississippi has made vigorous objections to the examiner's allocation, and indeed has opposed any allocation of the capacity devoted to industrial loads. Mississippi argues that the examiner's decision will impair its ability to serve its industrial customers and compel it to enlarge its facilities in violation of Secton 7(a) of the Act, that it is the service rendered, not merely a contract obligation, that is to be unimpaired, and that in any case the contracts show that the service rendered is firm service, not interruptible as found by the examiner, whose decision would cause destruction of all industrial sales.

Section 7(a) provides that "the Commission shall have no authority to compel the enlargement of transportation facilities" or "to compel such natural-gas company to establish physical connection or sell natural gas when to do so would impair its ability to render adequate service to its customers." The only difference between firm service and interruptible service is the utilities' contractual right to curtail delivery of gas. If the utility has the right to curtail service then the customers receive and pay for interruptible *service* even if the right of curtailment is not exercised. The issue thus turns not on actual deliveries but on the type of service which Mississippi is obligated to render to its existing industrial customers. The language quoted by Mississippi as typical of its so-called "firm contracts" with its industrials provides in part that, "It is expressly understood and agreed that Seller does not guarantee to Purchaser a constant supply of gas, and the delivery of gas to Purchaser will be curtailed from time to time and on occasion may be completely interrupted." Our previous decisions cited by Mississippi [13] describing its direct industrial sales as "firm" obviously refer to earlier language that was different. In our opinion sales covered by such contracts are interruptible,[14] although ranking above sales covered by other contracts containing language quoted by Mississippi to the effect that "Seller shall have the right to interrupt and discontinue the delivery of gas hereunder at any time and from time to time by giving two (2) hours prior notice * * *." The service to Mississippi's direct sale industrial customers, including the so-called firm customers, is thus interruptible and must be considered as such when determining whether it has been impaired.

Apart from the distinction between firm and interruptible service the allocation which we adopt herein will not result in such a reduction in service to Mississippi's industrial customers that service can be said to be impaired. In the first place there appears to be substantially greater capacity available in Mississippi's system above the 534,000 Mcf sustained capacity found by the examiner and used herein. As already noted the system delivered 555,785 Mcf on the peak day of the 1958–59 season. Further, some light is cast on the needs of the industrials by the emergency service rules effective for the period November 1, 1950,

[13] *Mississippi River Fuel Corp.*, 5 FPC 206, 209 (1946), and 6 FPC 280, 286–287 (1947).

[14] However, in the rate schedule changes we prescribe below we classify them as "firm industrial" to distinguish them from the sales that are more readily interruptible as indicated in the quote that follows in the text.

to February 2, 1952, issued under the authority of the Commission's opinion and order No. 198–A, 9 FPC 219. Under these rules Mississippi's industrials would be curtailed to 24,855 Mcf per day where the system capacity is 350,000 Mcf per day. In our opinion No. 198, July 27, 1950, 9 FPC 198, the nominal daily delivery capacity of the system was stated to be only 266,000 Mcf and the system peak day in 1949 only 300,000 Mcf. Yet these emergency rules were accepted and did not prevent peak deliveries to the industrials from reaching 65,756 Mcf on November 9, 1950.

Finally, if Mississippi wishes to continue service to its industrial customers at a higher level of sales, it may be able to obtain more gas from Transmission, its subsidiary, with which it plans to merge. While Transmission is authorized by us to deliver 75,000 Mcf per day to Illinois Power and Laclede, the record shows that its total capacity is 140,000 Mcf per day, and by further compression facilities this could be raised to 200,000 Mcf per day. Transmission could deliver gas to Mississippi's industrial customers through Mississippi's facilities or by delivering additional gas to Laclede which could decrease its takes from Mississippi by an equivalent amount. These transactions would require delivery of additional gas to Transmission, but the record indicates that Trunkline would be willing to increase its deliveries, and Natural Gas Pipeline of America would also like to supply gas to Transmission. Of course, this would require, as already indicated in connection with the settlement agreement, that certificate authority be obtained from this Commission and that all parties, including Trunkline and Natural, could make the necessary showing.

In our opinion, the allocation we are prescribing in the light of the indication in the record that the capacity of Mississippi's system for short periods is greater than that found by the examiner and the fact that we are allocating some 25,000 Mcf of gas per day to the industrial customers as firm industrial service, will avoid placing an undue burden on Mississippi or force it to enlarge its facilities. Whatever rights Mississippi has under its "grandfather" certificate,[15] its right to serve its industrial customers has been substantially retained when consideration is given to the non-firm nature of the service, the substantial capacity we are allocating to the industrials and the availability of gas from Transmission.

Mississippi also argues that its utility customers do not need an additional gas supply. It says that Laclede and Illinois Power can obtain additional gas from Transmission—at higher cost, of course. There is no reason to discuss Mississippi's arguments with respect to Illinois Power since we are not increasing its stated demand. As for Laclede, we see no reason why we should relegate it to the more expensive gas particularly when it has taken some already. Furthermore, Mississippi says, Laclede has underestimated possible withdrawals from its Lange storage field. On this point we think that Laclede's evidence, based upon the first hand knowledge of its facilities, is more persuasive, and furthermore, Laclede would prefer to use storage capacity rather than capacity purchased from Mississippi at a low load factor and therefore higher cost. With respect to Ark-La (MidSouth) Mississippi points to the fact that its stated demand was increased by 3,350 Mcf effective October 3, 1960, and that it is able to meet all demands by the use of penalty gas at lesser cost than if its stated demand were increased. Mississippi argues that the requirements of St. Charles would be met except for its large industrial load and that Missouri Natural would use the additional gas to serve an interruptible load. In our opinion, penalty gas is no sub-

[15] Issued March 1, 1944, 4 FPC 535.

stitute for a stated demand as its availability is questionable. The industrial and other requirements of St. Charles and Missouri Natural were taken into account in the staff allocation we are adopting here and priority was given to the non-industrial loads of Mississippi's customers. Furthermore, interruptible service would not be rendered by Missouri Natural on a peak day. We are thus treating all the industrial consumers, including those of Mississippi itself, on an equal basis.

The staff's proposed allocation was criticized by some of Mississippi's utility customers. Laclede objects to the staff taking into account that the current needs of Laclede and Illinois Power have been satisfied in part by Transmission. Since the needs of these companies have been met to this extent, it was perfectly proper for the staff to take this fact into account. As already indicated we are not satisfied with the arrangement by which the more expensive pipeline gas is sold to Laclede and Illinois Power, but this is not a rate case and the proper disposition of the rates of Mississippi and Transmission should be left to a later proceeding. Contrary to the contentions of Illinois Power, it was entirely proper in this proceeding to give priority to each resale customer's non-industrial load and to take into account Mississippi's industrial load, for this load should not be treated as inferior to the industrial loads of the resale customers. Ark-La (MidSouth) objects to the examiner reserving a quantity of gas for four of Mississippi's utility customers which did not participate in the proceeding. Our proceedings are designed to further the public interest. Although Union, Dupo, PUC Crossett and Ashley County were not participants, the record shows that they are Mississippi's customers and are in need of gas. Therefore, it is proper that gas be reserved for these customers for a reasonable time pending their application.

Turning to the matter of rate schedule changes, we note that Mississippi objects to the examiner's requirements. Among other changes he required that Mississippi file a rate schedule change providing that any buyer where requirements have not been met by it will remain a general service buyer under the F–1 Rate Schedule even though the buyer obtains gas elsewhere. Mississippi contends that the Commission would have to approve any such tariff change, including the reduction of a stated demand. We, therefore, agree with Mississippi's contention that the examiner's rate schedule change is not necessary.

Mississippi objects to the examiner's rate schedule change providing that excess gas on the system be sold to the F–1 buyers. Mississippi says that this would make it impossible to stay above the 72 percent load factor requirement in Mississippi's contract with United Gas Pipeline Company. We think it more equitable to adopt the staff's rate schedule changes providing that excess gas be made available on the basis of 50 percent to the resale buyers and 50 percent to Mississippi's direct industrial customers.

Mississippi further objects to the examiner's softening the overrun penalty which formerly ran up to $10 per Mcf for overruns in excess of 1,000 Mcf or 1 percent. Mississippi had already removed the 1,000 Mcf limitation and had permitted the taking of 2 percent of the stated demand in any billing month or for a total of 5 days by paying an additional 15 cents per Mcf. Mississippi had further offered to exclude from the computation those days when the excess was less than 1 percent. We think that in this case a $10 per Mcf penalty is too high. On the other hand, we think that the examiner's preservation of the 1,000 Mcf volume tolerance is unduly preferential to Mississippi's small customers. We shall, therefore, adopt the scale of penalties recommended by the staff providing for

the following payments in addition to the commodity charge: (1) 5.88 cents per Mcf for the first 2 percent or 100 Mcf whichever is greater, (2) $2 per Mcf for volumes in excess of 2 percent but not over 3 percent, (3) $5 per Mcf for volumes in excess of 3 percent or 100 Mcf, whichever is greater.

Mississippi contends that the examiner has been biased and that decisions tainted with bias are invalid. We have seen nothing that would lead us to believe that the examiner was biased or that the examiner's recital of the facts or his decision reflected bias. Since the present opinion and order adopts a substantially different approach, the question of bias is irrelevant, and it will not be necessary to discuss it further.

The Commission finds:

(1) Mississippi, having its principal place of business at St. Louis, Missouri, owns and operates a natural gas transmission pipeline system located in the States of Texas, Louisiana, Arkansas, Missouri, and Illinois, and by such operations Mississippi is engaged in the transportation and sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission, and is, therefore, a natural-gas company within the meaning of the Act as found by the Commission in its order of March 1, 1944, Docket No. G–291, 4 FPC 535.

(2) Laclede, Illinois Power, Ark-La and formerly MidSouth, St. Charles, Union, Missouri Natural, PUC Crossett, Dupo and Ashley County are each a person engaged in the local distribution of natural gas to the public and each purchases natural gas from Mississippi for resale for ultimate public consumption under the terms and provisions of Mississippi's FPC Gas Tariff, Original Volume No. 1.

(3) The settlement proposal filed by Mississippi on March 27, 1962, is not in the public interest when considered in the light of the record in this proceeding.

(4) The sustained dependable delivery capacity of Mississippi's system for future stated demand purposes is not less than 534,000 Mcf, of which not less than 447,303 Mcf is deliverable in the St. Louis area.

(5) Increasing the stated demands of each of Mississippi's utility customers, to the extent and in the manner provided in paragraphs (A) and (B) below, will not place an undue burden upon Mississippi and will not impair its ability to render adequate service to its customers.

(6) It is necessary and desirable in the public interest that Mississippi make the changes in or additions to its FPC Gas Tariff Original Volume No. 1 set forth in the attached Appendix B.

(7) It is necessary and desirable in the public interest that Mississippi be required to file applications for certificates of public convenience and necessity for authority to continue to serve such direct sales customers as it was not serving on the effective date of its "Grandfather" certificate.

(8) It is appropriate for the Commission to require that Mississippi file new or superseding service agreements containing the contract demands stated in paragraph (B) below.

The Commission orders:

(A) The settlement proposal filed by Mississippi on March 27, 1962, is hereby rejected.

(B) The stated demands of the following customers of Mississippi shall be as follows with the reservation noted below:

	Mcf
Laclede	338,347
Illinois Power	57,202
Union Electric	13,757
St. Charles	3,210
Dupo	775
Missouri Natural	33,521
Ark-La (MidSouth)	31,000
Ark-La	9,500
Chester	1,501
Hazen	558
Altheimer	350
Augusta	915
Des Arc	415
Fort Smith Gas Corp.	2,700
Red Bud	641
Direct Industrials	24,608
PUC Crossett	2,750
National Gas Improvement Dist. (Ashley County)	624

The increases granted Union (3,757 Mcf), Dupo (100 Mcf), PUC Crossett (750 Mcf) and Ashley County (250 Mcf) shall take effect only upon approval of applications filed by these customers within six months of the date this opinion and order becomes effective. Upon failure of any one or all of these customers to make timely application pursuant to Section 7(a) of the Act within said six-month period, or failure to support such application, such quantities shall be distributed pro-rata to the utility customers and to the industrial group in the manner utilized herein, by substituting in columns 10 and 11 of Appendix A hereof the supported stated demands. Hearings concerning the 7(a) applications of the four customers above shall omit the issue of gas supply, since this issue has been determined herein.

(C) Within 30 days Mississippi shall file the tariff changes set forth in Appendix B hereto.

(D) Mississippi shall file an application or applications for certificates of public convenience and necessity for authority to continue to serve such direct sales customers as it was not serving on the effective date of its "Grandfather" certificate.

(E) "Mississippi shall file new or superseding service agreements containing the contract demands stated in paragraph (B) above."

(F) Exceptions not granted herein are hereby denied.

APPENDIX A

Allocation of present system capacity of Mississippi River Fuel Corporation among its utility and direct industrial customers (volumes in Mcf of 14.9 psia 60° F.)

Particulars	Present or committed stated demands [1]		Requirements and supply of customers among whom available capacity must be allocated						Unavailable for industries		System capacity	Available for industries	Industrial sales of utility customers	Direct industrial customers	Prescribed stated demands	Allocated capacity
			Requirements			Supply			Present and committed stated demands	Other requirements to be supplied by Mississippi						
	Present [2]	Committed	Industrial	Other	Total	Mississippi	Other	Total								
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10) (2) and (3)	(11) (5) – (8)	(12)	(13) (12) – (10) – (11)	(14) [4]	(15) [4]	(16) (10) and (11) – (14)	(17) (15) and (16)
St. Louis area																
Utility customers:																
Village of Dupo				775	775	775		775		775					775	
Illinois Power Co	57, 202								57, 202						57, 202	
Laclede Gas Co			61, 300	628, 700	690, 000	375, 000	315, 000	690, 000		313, 700			24, 647		338, 347	
St. Charles Gas Corp			1, 302	3, 538	4, 840	3, 988	852	4, 840		2, 686			524		3, 210	
Union Electric Co			1, 050	13, 335	14, 385	14, 385		14, 385		13, 335			422		13, 757	
Total	57, 202		63, 652	646, 348	710, 000	394, 148	315, 852	710, 000	57, 202	330, 496			25, 593		413, 291	
Industrial customers:																
Pilot lights and space heating			[3] 5, 100		5, 100	5, 100		5, 100						2, 051		
Operations			[3] 45, 243		45, 243	45, 243		45, 243						18, 191		
Total			[3] 50, 343		50, 343	50, 343		50, 343						20, 242		
Total, St. Louis area	57, 202		113, 995	646, 348	760, 343	444, 491	315, 852	760, 343	57, 202	330, 496	447, 303	59, 605	25, 593	20, 242	413, 291	433, 533

Crossett compressor station to St. Louis																
Utility customers:																
City of Altheimer	350								350						350	
Arkansas-Louisiana Gas Co.	9,500								9,500						9,500	
City of Augusta	915								915						915	
City of Chester		[4] 1,501							1,501						1,501	
Town of Des Arc	415								415						415	
Fort Smith Gas Corp.	2,700								2,700						2,700	
City of Hazen			65	532	597	597		597		532			26		558	
Arkansas-Louisiana (Mid-South)				31,000	31,000	31,000		31,000		31,000					31,000	
Missouri Natural Gas Co.			300	33,400	33,700	33,700		33,700		33,400			121		33,521	
City of Red Bud		[5] 641							641						641	
Total	31,880	2,142	365	64,932	65,297	65,297		65,297	16,022	64,932			147		81,101	
Industrial customers:																
Pilot lights and space heating			549		549	549		549						221		
Operations			10,310		10,310	10,310		10,310						4,145		
Total			10,859		10,859	10,859		10,859						4,366		
Total Crossett compressor station to St. Louis	13,880	2,142	11,224	64,932	76,156	76,156		76,156	16,022	64,932	71,697	(9,257)	147	4,366	81,101	85,467
Total, north of Crossett compressor station	71,082	2,142	125,219	711,280	836,499	520,647	315,852	836,499	73,224	395,428	519,000	50,348	25,740	24,608	494,392	519,000

[1] Where no increase in stated demand is warranted.
[2] Fifteenth Revised Sheet No. 25 to Mississippi's Tariff Original Volume No. 1 effective December 2, 1961.
[3] Exhibit No. 101, Schedule 4 adjusted to reflect supplemental responses, Exhibit No. 100.
[4] Illinois Power Co., *et al.*, Docket No. G–14857, *et al.*, 21 FPC 190.
[5] City of Red Bud, Illinois, Docket No. G–16504, 25 FPC 987.
[6] Column 13 allocated on basis of Column 4.

APPENDIX B

Tariff Changes

RESTATEMENT OF GENERAL TERMS AND CONDITIONS NO. 7—PRIORITY OF SERVICES

7. *Priority of service:*

7.1 *Firm Service.* Firm Service rendered by Seller to its Buyers up to Buyers' Stated Demands shall have priority over all other services rendered by Seller.

7.2 *Firm Industrial Service.* Firm Industrial Service[1] rendered by Seller to its direct industrial customers shall have priority over all interruptible service rendered by Seller.

7.3 *Interruptible Service.* Interruptible Service rendered by Seller to its Buyers and direct industrial customers shall be the first to be curtailed in the event the demands on Seller's system for firm service and firm industrial service shall exceed available deliverable supplies.

7.4 *Rendering of Interruptible Service.* Interruptible Service shall be deemed to be volumes required by Buyers in excess of Stated Demands and by direct industrial customers in excess of an aggregate volume of 25,000 Mcf per day (excluding sales south of Seller's Crossett Compressor Station). Such volumes which Seller's system can deliver on any day in excess of the sum of 25,000 Mcf plus that portion of the total Stated Demands of its Buyers currently being delivered shall be made available on the basis of 50 percent to Buyers and 50 percent to direct industrial customers.

RATE SCHEDULE I–1. INTERRUPTIBLE GAS SERVICE

1. *Availability:*

This rate schedule is available to any purchaser (hereinafter called Buyer) receiving service from Mississippi River Fuel Corporation (hereinafter called Seller) under Rate Schedule F–1.

2. *Applicability and character of service:*

This rate schedule shall apply to all natural gas delivered by Seller to Buyer on an interruptible basis in excess of Buyer's Stated Demand upon request by Buyer pursuant to Section 7.4 of the General Terms and Conditions.

3. *Rate:*

26.88 cents per Mcf.

4. *Minimum bill:*

None.

5. *Heat content adjustment:*

If the average heating value of the gas delivered during any month is more than 1,005 Btu per cubic foot or less than 995 Btu per cubic foot, the rate shall be increased at the rate of 0.78 percent or decreased at the rate of 0.78 percent for each 10 Btu above 1,005 or below 995 Btu per cubic foot.

6. *Measurement base:*

Refer to Section 1 of the General Terms and Conditions.

7. *General terms and conditions:*

The General Terms and Conditions are part of this rate schedule.

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[1] Definition under General Terms and Conditions No. 15:

Firm Industrial Service: Firm Industrial Service is deemed to be volumes required by Seller's direct industrial customers for pilot lights, space heating and such uses required in specific instances to prevent physical damages in the aggregate volume of 25,000 Mcf per day.

RESTATEMENT OF SECTION 6 OF RATE SCHEDULE F-1

6. *Payment for volumes exceeding stated demand:*

(a) Volumes taken in excess of the Stated Demand shall be presumed to be delivered under Rate Schedule I-1 except when Seller is providing only Firm Service and Firm Industrial Service pursuant to Sections 7.1 and 7.2 of the General Terms and Conditions.

(b) For each day when Seller is not rendering Interruptible Service pursuant to Section 7.3 of the General Terms and Conditions that the volume of gas taken by Buyer exceeds the Stated Demand, Buyer shall pay for such excess in addition to the commodity charge otherwise applicable as follows:

For any part or all of the first 2 percent or 100 Mcf, whichever is greater, 5.88 cents per Mcf.

Volumes in excess of 2 percent but not over 3 percent, $2 per Mcf (for buyers whose stated demand is over 5,000 Mcf).

Volumes in excess of 3 percent or 100 Mcf; whichever is greater, $5 per Mcf.

(c) The payment for volumes of gas taken in excess of the Stated Demand on days when Seller is not rendering Interruptible Service pursuant to Section 7.3 of the General Terms and Conditions does not grant Buyer the right to take such excess volumes, nor shall such payment exclude or limit any other remedies available to Seller against the Buyer for failure to limit the quantity of gas taken to its Stated Demand.

DECISION

UPON A COMPLAINT AND APPLICATIONS FOR ORDERS DIRECTING INCREASES IN STATED DEMANDS

(Issued September 13, 1960)

HALL, *Presiding Examiner:* Involved here are three applications filed under Section 7(a) of the Natural Gas Act (Act) and a complaint filed by Laclede Gas Company (Laclede) under Section 5(a) of the Act upon which the Commission instituted an investigation.[1] All are directed against Mississippi River Fuel Corporation (Mississippi), a Delaware corporation with its principal office in St. Louis, Missouri.

Laclede, by far Mississippi's largest customer, is engaged in the retail distribution of gas in the City of St. Louis and St. Louis County, Missouri. It has failed to obtain from Mississippi the additional gas to which it believes it has been entitled, and it is and has been in need of a substantial additional gas supply to meet the unsatisfied and constantly increasing requirements of its service area. Its diligent efforts to obtain additional gas from Mississippi on an acceptable basis have been to no avail because of Mississippi's interest in protecting and promoting its profitable industrial sales. Moreover, Laclede has no assurance that Mississippi will make needed gas supplies available to it on an appropriate basis in the future. In these circumstances the normal development and expansion of Laclede's gas business has been and is severely

[1] The Commission set for hearing a consolidated proceeding involving five 7(a) applications and Laclede's complaint. Two of the 7(a) applications, namely, those filed by Natural Gas Improvement District No. 2 of Ashley County, Arkansas (District), in Docket No. G-17942, and the City of Red Bud, Illinois, in Docket No. G-16504, sought initial service from Mississippi. District's unopposed application was severed and granted (22 FPC 1039). The City of Red Bud's application has been considered in a separate decision issued by the Examiner on July 25, 1960.

impeded and the public interest adversely affected. In short, Laclede is finding its tie to Mississippi to be a tie that binds rather than one that strengthens.

Laclede has had a long standing need for additional quantities of pipeline gas and is a full requirements customer of Mississippi.[2] Because of this and its awareness that the 7(a) applicants herein seek additional supplies of gas from Mississippi's existing capacity and that the Commission in prior proceedings has granted other 7(a) applications for service from Mississippi, Laclede filed its complaint seeking a determination of Mississippi's present sales capacity and the extent to which the limitation imposed by the 330,000 Mcf fixed for Laclede in Mississippi's FPC Gas Tariff may be relaxed. The complaint also seeks relief from certain other provisions of Mississippi's tariff and the practices of Mississippi thereunder, such provisions and practices being alleged to be, under present ciircumstances, unjust and unreasonable, resulting in undue prejudice and disadvantage to Mississippi's utility customers.

The 7(a) applicants, namely, MidSouth Gas Company (MidSouth), Illinois Power Company (Illinois Power), and St. Charles Gas Corporation (St. Charles), are, like Laclede, existing utility customers of Mississippi. They also need additional supplies of natural gas to meet their steadily increasing requirements and believe that Mississippi has existing capacity that can safely be made available for increasing their stated demands.

Mississippi objects to the issuance of an order herein directing it to sell and deliver additional natural gas to its existing utility customers, contendng that such an order would exceed the statutory authority of the Commission primarily because it would impair Mississippi's ability to render adequate service to its interruptible industrial customers.

Mississippi is engaged in the business of purchasing, transporting and selling natural gas to two classes of customers: (1) utility distributing companies and (2) industrial customers. Its tariff applicable to utility customers provides for only one service under one rate schedule (except for one minor standby service not important here). Whenever the utility customers exceed their stated demands (stated demands are equivalent to contract demands) now in effect they pay a substantial penalty. On the other hand, Mississippi sells gas in excess of contract volumes to industrial customers without penalty, thereby preventing the utility customers from sharing in excess gas available from time to time on its system. In addition to according its industrial customers this preference, Mississippi's tariff penalizes the utility customers, in particular Laclede and Illinois Power,[3] in still another way in that it effectively prevents such customers from taking their full stated demands. Laclede, for example, has been unable to come within some 6,000 Mcf of taking its full stated demand (330,000 Mcf) on most days of the heating season because of the existing tariff penalty provisions. Mississippi agrees that the tolerance provision of its tariff works unfairly to deprive at least some of the utilities of their full stated demands. It does not, however, agree with other proposed revisions of and additions to its tariff.

Two related matters are therefore presented for determination. First are the requests for increases in stated demand for existing utility customers. Second is the proposed revisions and additions to Mississippi's tariff to prevent undue prejudice and disadvantage to the utility customers.

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[2] Laclede's gas supply contract with Mississippi provides that the latter "will proceed with due diligence to install facilities or otherwise provide to meet Laclede's total requirements during the remainder of this agreement."

[3] Laclede and Illinois Power make up 82 percent of Mississippi's utility load.

Procedural Background

Laclede's complaint and the 7(a) applications were consolidated for hearing and determination by notice of April 27, 1959, and order issued May 21, 1959, and an investigation instituted upon the complaint (21 FPC 701).

The hearing on the complaint and 7(a) applications began on June 30, 1959, and, with various recesses, continued through October 14, 1959. The record made covered 18 days and the testimony of numerous witnesses and consisted of 2,277 pages of testimony, 73 exhibits and a large number of items.

The parties to this proceeding are Laclede, Mississippi, the 7(a) applicants, the Commission staff, and the following interveners: Missouri Natural Gas Company and Union Electric Company (public utility customers of Mississippi), the City of St. Louis, Missouri, and industrial cutomers directly served by Mississippi, namely, Granite City Steel Company, American Brake Shoe Company, Owens-Illinois Glass Company, Obear-Nester Glass Company, Olin Mathieson Chemical Corporation, C. K. Williams & Company, American Zinc Company of Illinois, Pittsburgh Plate Glass Company, Lewin Mathes Company, Alton District Manufacturers' Association, and Missouri Rolling Mill Corporation.

Briefs have been filed by counsel for Laclede, Mississippi, the 7(a) applicants, the above-named industrial customers directly served by Mississippi, Missouri Natural Gas Company and the Commission staff.

Mississippi's Customers

Utility Customers

As already stated, Mississippi is engaged in the business of purchasing, transporting and selling natural gas to two classes of customers: (1) public utilities and (2) industrial. The public utilities to which Mississippi sells gas and their stated demands are:

Customers	Stated demands (Mcf)
Arkansas Louisiana Gas Company	12, 900
City of Altheimer	400
City of Augusta	858
City of Chester	641
City of Hazen	456
Fort Smith Gas Corporation	2 700
Illinois Power	56, 323
Laclede	330 000
MidSouth	22 790
Missouri Natural Gas Company	24 000
Public Utilities Company (Crossett, Ark.)	1, 900
St. Charles	2 360
Town of Des Arc	415
Union Electric Company	10, 000
Village of Dupo	675
Natural Gas Improvement District No. 2 of Ashley County, Arkansas	374
Total	466. 792

Mississippi does not have service agreements with eleven of its utility customers, namely, Arkansas Louisiana Gas Company, Cities of Augusta, Chester and Hazen, Illinois Power, Public Utilities Company (Crossett, Arkansas), St. Charles, Town of Des Arc, Union Electric Company, Village of Dupo, and Natural Gas Improvement District No. 2 of Ashley County, Arkansas. The reason

for Mississippi's lack of service agreements with these utility customers is not apparent from the record. However, as they know, service to them is protected by the provisions of Mississippi's tariff, to the extent provided therein, and by the provisions of the Act to which Mississippi is subject. Accordingly, these customers can and have ignored such threats as the following testimony shows the Chief Executive Officer of Mississippi directed to a Vice President of Illinois Power:

> Q. Did you discuss the possibility of obtaining supplies for your supply area "C" from other sources than Mississippi.
>
> A. Yes. I mentioned to Mr. Marbury that we badly needed additional gas in Southern Illinois, and that we might have to look for other sources.
>
> Mr. Marbury then told me that if we were to buy any gas from any other supplier to be brought into the market area then served by his company, he would file abandonment proceedings against us with the Federal Power Commission—and I again use his words—"So fast it would make your head swim."
>
> He drew attention to the fact that our contract with his company had expired and that no matter how little gas we might buy from another supplier, he would immediately seek to abandon service to us.
>
> Q. What did you say in reply to this?
>
> A. I told him I could not let that comment go unanswered, and that so long as his company continued to be our major supplier in that area, his threat of an abandonment of service did not particularly disturb or frighten me, nor would I let any such threat lead me to the decision to buy any of this new gas from the proposed new subsidiary which I didn't think was economically practical.
>
> Q. Now, were any other matters discussed at this meeting, Mr. Davies?
>
> A. Yes, we discussed our 7(a) proceedings against his company to obtain gas for the towns of Millstadt, O'Fallon and Hamel.
>
> Mr. Marbury told me that if we and his other purchasers—that is utility purchasers, continued to nibble away at his existing pipeline capacity through this sort of 7(a) proceedings, it was probably our idea that we could do so at the expense of his direct sale customers.
>
> He stated that he intended to continue these direct sales at their present levels, and that if we were successful in prosecuting these 7(a) cases, he would not decrease his sales to his industrials, but would continue them at their present level, and if this resulted in a drop in the pipeline pressure at our delivery points, that was just too bad.
>
> He reminded me that Illinois Power was out at the end of the line.
>
> Q. What was your response to this?
>
> A. I again told Mr Marbury—to rephrase that—I told Mr. Marbury that I doubted if the Federal Power Commission would tolerate any such action and that this threat didn't particularly disturb me either.
>
> He told me that if there was a pressure drop he would never restore it until the FPC made him do it.

The foregoing testimony reflects a recognition on the part of the Chief Executive Officer of Mississippi that the Commission has the power to compel the restoration of pressure drops, etc. The utility customers may be assured that they will be afforded the full protection of the law. In connection therewith the Commission, if necessary, can invoke the penalty powers embodied in the Act for any willful and knowing violation of the provisions of the Act and orders, regulations, etc., issued thereunder (Sections 21, 22).

Industrial Customers

Although each of Mississippi's contracts with its industrial customers provides for interrupting service to such customers, Mississippi regards some of the industrials as firm customers, they being sometimes referred to in this proceeding as "firm-interruptible" customers.

Mississippi now has about 45 direct sale customers, several of which were not served on the effective date of its Grandfather certificate.[4] Mississippi took on some of the new industrial customers, without Commission authorization, through contract assignments even in instances where service to former customers had been discontinued for substantial periods. In two instances Mississippi initiated service through the installation of facilities (meter station and meter station and lateral to serve Sterling Steel Castings Company and Hill Brick Company) for which it sought no certificate authorization from the Commission.

Staff counsel recommends that Mississippi be required to file proper applications for certificate authorization to serve such direct sale customers as it was not serving at the time it received its Grandfather certificate. This recommendation is adopted by the Examiner. Staff counsel further recommend that Mississippi be required to amend its contracts with its existing so-called "firm-interruptible" industrial customers so as to show the actual permissible maximum daily takes of such customers and file such amendments. The Examiner does not agree with this recommendation for the rights of the parties are fixed by the terms of the previously executed contracts and they should not be permitted at this late date, when the utility customers are seeking increases in their stated demands, to acquire a status superior to that of the utilities.

History of Mississippi's System

Mississippi began operations in 1929. Originally it had a single pipeline extending in a northerly direction from Perryville, Louisiana, through the States of Arkansas and Missouri, and into the State of Illinois. Its present system consists principally of two main trunk transmission lines, approximately 431 miles long, extending from Perryville, Louisiana. Line No. 1 terminates in Missouri and Line No. 2 terminates in Illinois. Its principal sales take place in the vicinity of St. Louis, Missouri, and East St. Louis and Alton, Illinois.

In 1929, when Mississippi was constructing its initial transmission system, MidSouth's predecessor, Arkansas Power & Light Company (Arkansas), entered into a contract with Mississippi to purchase natural gas for distribution in eleven of the eighteen Arkansas cities presently served by MidSouth under its full requirements agreement with Mississippi. The 1929 full requirements contract provided that Mississippi would sell and deliver to Arkansas all of the natural gas requisite for the supply of the domestic consumers in those cities and environs. That contract further provided that Arkansas was to use every reasonable effort to increase sales of natural gas to residential, commercial and industrial customers and detailed the methods to be used by Arkansas in accomplishing this objective.

The first deliveries by Mississippi to MidSouth's predecessor were begun on December 11, 1929, making it the first utility customer of Mississippi. Only two industrial customers had received deliveries from Mississippi prior to that date, one on November 21, 1929, and the other on December 11, 1929.

[4] The Examiner is unable to determine the precise number from the record. Staff counsel refer to ten in their brief. Counsel for Laclede say there are nineteen. The precise number is unimportant for present purposes.

In finding Mississippi to be a natural-gas company in 1940 the Commission disagreed with Mississippi's claim that it was organized and its properties financed and constructed with the view of transporting and selling natural gas primarily for industrial use (2 FPC 170, 173–174). The Commission said:

> It is the contention of respondent [Mississippi] that its company was organized and its properties financed and constructed with the view of transporting and selling natural gas *primarily* for industrial use, and that whatever sales have been made by it to distributing companies for general public consumption have constituted only so-called "nuisance" sales along the route of the pipe line.
>
> The evidence discloses, however, that at the very outset of the financing and construction of the line respondent deviated materially from the alleged purpose of confining its operation to the service of selected industrial customers. In the public circular describing the proposed issue of mortgage securities for the construction of the line, the public is advised that, in addition to concluding contracts for the sale of gas to large industrial customers,
>
> > Arrangements are being consummated with Arkansas Power & Light Company, * * * the Arkansas Natural Gas Company, * * * and the Missouri Natural Gas Company for sale of gas to these companies for distribution in communities along the route of the pipe line in the States of Louisiana, Arkansas, and Missouri.
>
> Respondent, by contracts entered into with the Arkansas Power & Light Company, the Arkansas Natural Gas Company, and Missouri Natural Gas Company, agreed to supply these distributing companies with all their requirements for natural gas for distribution in approximately 30 cities and towns in the State of Arkansas and Missouri.
>
> Moreover, under two of these contracts it obligated itself to construct the requisite branch lines from its main trunk pipe line to points near the city boundaries of the cities in which these distributing companies proposed to sell the gas for domestic, commercial, and other purposes. These contracts provide that preference be given the requirements of domestic consumers over industrial consumers, in the event of shortage of gas; that the distributing companies maintain every possible effort to increase sales of natural gas for house heating, cooking, and all other domestic uses; and domestic consumers are defined as including "private homes, boarding houses, apartment houses, hospitals, [and] charitable institutions."

The designed daily sales capacity of Mississippi's original system was about 100,000 Mcf. By 1942 it had increased to 135,000 Mcf. Mississippi's second line project, i.e., looping program, involving an increase in sales capacity from 135,000 Mcf to 183,000 Mcf was commenced pursuant to certificate authorization granted on August 28, 1946. The Commission's opinion recited in part (5 FPC 206, 209–210):

> The peak day sales of the applicant in 1944 consisted of 43 percent sales to utilities and 57 percent sales to direct industrial customers. In the following year the peak day sales to utilities rose to 60 percent of the total, while the sales to direct industrial customers fell to 40 percent.
>
> On the basis that the facilities, sought in this application, if authorized, will be in operation for the peak day of 1947–48, applicant estimates that of the total daily sales capacity of 181,000 Mcf, 83 percent will go to the utility customers and 17 percent to the industrial customers. *For the peak day of 1950, it appears that unless additional facilities are installed, almost 100 percent of the system sales capacity of 181,000 Mcf will be devoted to utility sales.*

> Applicant estimates that with presently proposed facilities, it will be necessary to curtail its firm industrial sales on system peak day for each of the calendar years 1946 to 1950, inclusive. * * * *Applicant has indicated its intention to add facilities to increase the capacity of its system from time to time as warranted by the increases in demands.* * *

As the Commission recognized, all of Mississippi's system capacity would eventually be devoted to utility sales unless Mississippi increased the capacity of its system from time to time.

Authority to complete the above referred to looping program of Line 2, to be operated at 700 pounds pressure giving a system daily design sales capacity of 266,000 Mcf, was granted by the Commission on December 8, 1947 (6 FPC 280). In connection therewith it was estimated that on the peak day in the years 1947 through 1951 Mississippi would have to curtail deliveries to its direct industrial customers in order to meet the demands of its resale customers.

The system design sales capacity was increased by successive steps from 266,000 Mcf in 1950 to 450,000 Mcf in 1952, exclusive of any gas that might become available from Waterloo storage (9 FPC 219, 9 FPC 1187; 11 FPC 760; 11 FPC 1219). In connection therewith, and because an acute shortage had developed on Mississippi's system, Mississippi was required to file emergency service rules to govern deliveries of natural gas to all of its customers. Such rules became effective as of November 1, 1950, and as subsequently amended were to continue in effect through March 31, 1953, or until such time as Mississippi's aggregate sales capacity would exceed 450,000 Mcf, whichever occurred first. Such rules were terminated as of March 31, 1953.

In 1952 the Commission, in Docket No. G–1281, et al. (11 FPC 1219), and subsequently on June 3, 1953 (12 FPC 151), made the latest allocation it has made of Mississippi's capacity. The then claimed total delivery capacity of Mississippi's system was 450,000 Mcf, of which 415,000 Mcf, or 92 percent, was allocated to utility customers and 35,000 Mcf, or 8 percent, was permitted to be used in connection with Mississippi's industrial sales. In that connection the Commission adopted an agreed-to schedule of stated demands allocating the 92 percent of Mississippi's capacity among its utility customers on the basis of a stipulation that the amounts stated would not affect rights under existing utility contracts.

While Mississippi and the other parties agreed to the allocation of 450,000 Mcf, represented by Mississippi to be the design sales capacity of its system, the record shows that in the summer of 1952 Mississippi, *without certificate authorization*, increased its system sales capacity by some 50,000 Mcf, or to 500,000 Mcf, by "pigging" a portion of one of its two transmission lines, adding some horsepower to raise the pressure on its two lines by 25 psi each, and by the installation of "cross-overs" between its two lines.

Today, Mississippi claims that its design sales capacity is 524,000 Mcf, an increase of 74,000 Mcf over the 450,000 Mcf capacity alleged in 1952 and 1953. Except for (1) 10,000 Mcf additional capacity authorized by order of August 2, 1957, (18 FPC 106) and (2) a claimed 7,000 Mcf additional capacity authorized by order of October 14, 1958, in Docket No. G–15190, or a total of 17,000 Mcf additional capacity, the claimed increase of 74,000 Mcf between the 450,000 Mcf and the alleged 524,000 Mcf design sales capacity as of today *was accomplished without Commission authorization.*

In connection with the above referred to 10,000 Mcf additional capacity authorized on August 2, 1957, Mississippi's utility customers complied with its request that they support the application therefor without requesting an allocation of the 10,000 Mcf, they being of the opinion that Mississippi would proceed with another application to provide an additional 50,000 Mcf capacity. Such an application was never filed.

On May 19, 1958, Laclede's President wrote a letter to Mississippi inquiring as to what it proposed to do concerning the matter of furnishing additional gas to Laclede. On May 28, 1958, Mississippi replied that "It is our intention to bring to St. Louis whatever additional quantities of gas the market requires" and requested Laclede to advise Mississippi as to its requirements. By letter dated June 5, 1958, Laclede advised Mississippi of its willingness to take all or any part of 100,000 Mcf per day at any time prior to the fall of 1960.

Instead of proposing to enlarge its existing facilities for the purpose of increasing its supply of gas to its customers, Mississippi, on October 25, 1958, announced in the daily press that it had organized a new corporation known as Mississippi River Transmission Corporation to bring in an additional supply of gas from a point on Texas Eastern Transmission Corporation's line near Oran, Missouri. Thereafter, on December 5, 1958, a conference was held in Laclede's offices attended by representatives of Mississippi, Laclede and Illinois Power in which the details of the proposed new line were outlined. Laclede then indicated that it would be interested in the program as outlined if it could be set out in greater detail and certain changes in the delivery requirements could be made.

On December 19, 1958, Mississippi advised Laclede as to the details of the proposal which were substantially different from the proposal outlined at the December 5th meeting. At several subsquent conferences the President of Laclede advised Mississippi that its latest proposal was not acceptable to Laclede, and on February 5, 1959, wrote Mississippi formally rejecting the proposition, primarily because of price. That proposal also included a monthly 75 percent take-or-pay provision which Laclede regarded as unjustifiably saddling the utility customers with the major cost of the new line, although the industrial customers would have received much of the benefit.

A Vice President of Illinois Power, in explaining the opposition of his company to Mississippi's proposal, threw Mississippi's interest and attitude in clear focus when he testified as to what took place at the above referred conference held on December 5, 1958:

> A. Illinois Power thought that not only the price but several other provisions of this deal made it very unattractive for Illinois Power Company.
>
> Accordingly we told them * * * that as far as Illinois Power * * * was concerned we were not interested in that proposition.
>
> Q. Did you give them any reasons?
>
> A. Yes, I did.
>
> Q. What were the principal reasons?
>
> A. As I have said, the price was unattractive and would have lifted our average cost of gas quite a bit. In addition to that there were two other factors. By having to buy the gas through a new and separate subsidiary, we could not take advantage of the automatic cost of gas adjustment clause in our field rate schedules to recoup this increased cost.
>
> And we would have to file a separate rate increase application on top of an increase which * * * had just prior thereto been granted to us by the Illinois Commission.
>
> To explain that further: If the gas had been bought by us from Mississippi * * *, it would have represented an increase in price on our existing supply and our automatic cost of gas adjustment clause would have taken care of that.
>
> But a new source of supply was not covered in our automatic cost of gas adjustment clause.
>
> Q. Were there any other considerations that caused you to turn down this proposition?

A. Yes. We found that the 75 percent take-or-pay provision which was a monthly 75 percent take-or-pay provision would have been very burdensome to us. This would have required that we buy a substantial amount of our spring, summer and fall gas under the provisions of this new contract to satisfy this provision.

This would mean that we would substantially reduce our purchases from Mississippi under our existing contract under which we were then buying gas at substantially lower prices. This would have increased the quantities of gas that Mississippi would then have available for sale to its direct sale customers.

It was our feeling that the net effect of this whole proposition would be that we and Laclede would be paying—I might say we, Laclede and other utility customers that might have been involved—would be paying the entire cost of the increased gas supply and that the direct sale customers would be getting many of the benefits of the increased supply at no increase in cost to them.

Q. Did you indicate, nevertheless, * * * that you did continue to have an interest in increased quantities of gas from Mississippi?

A. Yes. * * *

Q. Can you relate any other particulars of this conversation?

A. Yes. I suggested * * * that they consider having this increased capacity owned by Mississippi * * *—or at least sold to us by Mississippi * * *—and that it make the sales to our company under a rolled-in rate.

Q. What was their reaction to this suggestion?

A. * * * Mr. Marbury told me that neither he nor his Board would even consider any such proposition.

He stated that because of their rate and their regulatory situation they had no intention of expanding the existing Mississippi * * * system.

The officials of Laclede present at the meeting also stated that they would prefer the rolled-in supply. And Mr. Marbury on several occasions during the meeting reiterated that his company would give no consideration to supplying gas on this rolled-in rate basis, and that it was—and I use his words—"The new subsidiary or nothing."

The foregoing testimony justifies the conclusion that Mississippi lacks the incentive to provide its utility customers with their needs in a manner compatible with the over-all public interest; that it is doing everything possible to protect and increase its industrial sales, and that this is being done to the detriment of the utility customers and the areas they serve.

History of Mississippi's Supply of Gas to Laclede

Laclede is engaged in the retail distribution of gas in the City of St. Louis and St. Louis County, Missouri, an area undergoing rapid growth. It distributes straight natural gas supplemented by propane and other manufactured gas and and by use of Laclede's underground storage facilities developed at great expense.[5]

Laclede began purchasing natural gas from Mississippi for mixing purposes in 1942, converting to straight natural gas in 1949. As has been typical in such

[5] Laclede's peak day during the 1958–59 heating season occurred on January 4, 1959, when it sold slightly in excess of 473,000 Mcf of gas. Of that amount, it withdrew 96,230 Mcf from storage, manufactured 67,415 Mcf and received 325,000 Mcf from Mississippi. Laclede did not receive its full stated demand of 330,000 Mcf from Mississippi on that day because the tariff penalty provision made it inadvisable for Laclede to attempt to take its full entitlement.

situations, Laclede's need for natural gas sharply increased following that conversion.

During the period from 1950 to 1958 Laclede's house-heating customers increased from 92,532 to 190,158 and its industrial customers increased from 6,971 to 9,242. It presently has 17,500 applications for space heat. Since 1950 Laclede has operated under some form of restriction as to the acceptance of new customers. A large potential has been, and continues to be, deprived of natural gas service. The house-heating saturation in Laclede's service area is only 55 percent.

Laclede estimates that its peak day requirements (0 degrees at year end) from 619,000 Mcf in 1959 to 852,000 Mcf in 1963, and a further increase to 952,000 Mcf in 1966. Much of this estimated increase represents a programmed effort to meet existing unsatisfied demands for gas service which has built up over the past ten years. It must obtain additional pipeline gas if it is to satisfy its public service obligation.

Laclede's most recent contract with Mississippi, executed in 1947, provided for a maximum of 200,000 Mcf per day. In 1950 Mississippi entered into a full requirements contractual obligation with Laclede. When the emergency rules governing Mississippi's deliveries to its various classes of customers went into effect on November 1, 1950, Laclede was assigned a peak day maximum of 268,000 Mcf. This was increased to 300,000 Mcf in 1952 and 330,000 Mcf in 1955. Accordingly, in the last ten years Mississippi has made available to Laclede only 62,000 Mcf of additional natural gas.

Laclede has repeatedly sought substantial additional pipeline gas from Mississippi. On March 25, 1957, it formally requested an additional 100,000 Mcf for the 1958–59 heating season. In February 1957 Mississippi had filed with the Commission an application for a certificate authorizing the construction and operation of facilities to increase Mississippi's pipeline capacity by approximately 50,000 Mcf per day. However, in March 1957 Mississippi withdrew that application and substituted an application for facilities to provide only 10,000 Mcf per day and requested its customers to support the application *without asking for an allocation of the 10,000 Mcf*. The customers complied with this request. The certificate was issued on August 2, 1957 (18 FPC 106). In that connection Laclede's President testified: "We had expected, although I must say it was never guaranteed to us, that upon completion of the project * * * Mississippi would proceed with the original project and that our share of the increase of 50,000 Mcf based on an allocation among utility customers would be about 35,000 per day. Numerous conferences were held during the remainder of 1957 and on into 1958 without result."[6]

It was on May 19, 1958 that Laclede's President wrote the letter hereinabove referred to (pp. 719–720, *supra*) inquiring as to Mississippi's intentions concerning the matter of furnishing additional gas to Laclede, such inquiry, and the conferences that followed, resulting in Mississippi's unacceptable proposal to organize a subsidiary to construct a new separate pipeline system instead of enlarging its

[6] In a letter dated August 19, 1957, addressed to Mississippi, the President of Illinois Power stated that he was "quite unhappy" about what was happening. He explained: "We have recently heard that your corporation has changed its plans concerning the application for an additional 40 million cubic feet a day * * *. I was quite surprised to learn this because Mr. Kramer clearly indicated you were going to proceed with the application for 40 million cubic feet capacity when he requested my help with respect to the 10 million cubic feet, and we have previously advised your corporation in writing that we were prepared to contract for an additional 45 million cubic feet a day regardless of whether or not we find storage."

present system so that both industrial and utility customers would share equitably in the increased cost of the new gas supply and facilities.

Origin of Problems Presented

The issues, to be fully appreciated, must be considered not only against a background of Mississippi's history, method of operation and present position, but also against a background of the effect of the unchecked rise in prices paid producers for natural gas purchased, transported and sold by pipeline companies such as Mississippi.

As has been explained, Mississippi's business has always consisted in part of the transportation and sale of natural gas to public utilities for resale, and in part of transportation and sales to industrials for their use and consumption. While the Commission's jurisdiction extends to (1) the *transportation* and *sale* of natural gas to utilities for resale, and (2) to the *transportation* of gas to industrials, it has no regulatory authority over rates charged by pipelines to industrials. Thus pipelines such as Mississippi have been free to charge industrial customers "what the traffic will bear" rates which have been very lucrative. As the Commission explained in a Mississippi rate decision rendered November 5, 1945 (4 FPC 340, 343, 351) :

> After the early development period when the capacity of the pipeline greatly exceeded the volume of gas sold, Mississippi has enjoyed exceptionally high earnings, and has maintained the payment of large dividends to stockholders.
>
> * * * * * * *
>
> From the beginning, the business of the company has been predominantly the sale of natural gas to industries, but the proportion of the sales to utilities for resale has increased constantly to the point where revenues from sales to utilities for resale constituted 32% of the total in 1943. The company estimates that in the immediate post-war period revenues from sales to utilities will be about 35% of the total. * * * The rates for gas sold directly to industrial customers are not subject to our jurisdiction * * *.

A serious problem particularly for pipelines and distributors has been created and is now endemic in the industry. This problem results largely from the rapidly increasing field prices which producers are permitted to charge and is daily becoming more serious because, among other things, the higher such prices are permitted to go the greater the erosion of profits from industrial sales. Thus the higher field prices are making it progressively more difficult for pipelines to continue making industrial sales at desired profits. This in turn is causing pipelines to seek ways and means of offsetting the increased producer prices, as well as the higher cost of new facilities, to protect industrial sales and their profitability.

An unfortunate corollary of the problem of accelerated producer prices has been the reluctance of pipelines to "roll in" the higher costs of newly purchased gas as part of their total cost of service. In explaining the "rolled-in" rate method in *Battle Creek Gas Co. et al.*, v. *FPC., et al.*, 281 F. 2d 42, the Court pointed out, *inter alia*, that "the cost of the various assets of the system are collected or 'rolled in' to arrive at the cost of the entire system which is then pro-rated among all of the customers" and that—

> The rolled-in rate method is generally disadvantageous * * * to old customers of an expanding pipeline. The cost of new facilities and new gas historically has risen steadily, and a rolled-in rate requires old customers to pay a higher price and bear part of the cost of an expansion from which

> they receive little visible increase in service. But, conversely, use of the rolled-in approach insures that two otherwise similar customers will not pay radically different prices for commingled gas coming from the same pipe, merely because one happens to have been receiving the service longer than the other. Use of the rolled-in method thus serves the interest of equal treatment for customers receiving equal service.

The normal effect of a "roll-in" is to increase the cost of gas available to the pipeline on an overall basis. The next effect is to make it difficult to sell gas for industrial purposes at rates and profits comparable with those in the past. As a result there have been an increasing number of cases where the pipeline seeks to "tilt" the rates so that they can sell a large volume of industrial gas. The effect of the "tilt" is often to place an unfair share of the burden upon the householder or commercial user as compared to the burden of the industrial user. To put it another way, the increased cost of gas at the wellhead results in attempts by pipelines seeking to preserve the industrial business to charge unfair and discriminatory prices to the average user. This problem comes into sharp focus in these proceedings. As already shown (*supra*, pp. 719–721), the pipeline in this case sought, in 1958, to deal with this general problem not by "tilting" its rates but by the creation of a subsidiary to construct and operate a new and separate pipeline system. This Mississippi proposed notwithstanding the feasibility of looping or otherwise increasing the capacity of its present system (as it has done in the past and could do now if it had the necessary incentive). If that procedure, which had to be rejected by its utility customers, had been followed it would have, among other things, circumvented rolled-in rates by keeping the additional and more costly gas supply and facilities from being integrated into Mississippi's over-all cost of service, and would have saddled the utility customers with a disproportionate share of the higher cost gas supply and facilities, thereby promoting Mississippi's industrial sales.[7]

In *Mississippi River Fuel Corp.* v. *F.P.C.*, 252 F. 2d 619, 624, Mississippi opposed the higher single rate there involved because it was injurious to its direct industrial sales. The Court held, however, that the reasons for Mississippi's opposition to the single rate—

> * * * While * * * potent from the standpoint of that company, they do not avail too much from the standpoint of general regulation and the public interest.

Of significance here is the testimony of Mississippi's Chief Executive Officer who makes it clear that, contrary to the intent of the Act, Mississippi's Management proposes to continue to give priority to industrial sales:

> We feel a grave responsibility to the basic large industry that we serve with firm gas and have served for many years. We feel that that was our original business in the main. We have been authorized to engage in it. The people rely on us. The economic well-being of the community to a great extent is dependent upon it. And we intend to fulfill our obligation. And, therefore, we want to reserve for our own customers sufficient gas to let us fulfill our responsibilities to them.

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[7] Another attempt (in modified form) by a pipeline to avoid rolled-in rates and to saddle a distributing company with the cost of higher priced gas and new facilities was unsuccessfully advanced in the *Trunkline Gas Company* case (21 FPC 704, 711, 739–746), a plan which would have promoted the direct industrial sales program of Panhandle Eastern Pipeline Company. This case was reviewed by the United States Court of Appeals of the District of Columbia Circuit in *Battle Creek Gas Company, et al.* v. *Federal Power Commission, et al.*, 281 F. 2d 42.

After that amount of gas is served, we are willing and anxious to devote all the rest of our capacity to the requirements of our resale customers, both present and future. [Emphasis supplied.]

Mississippi's position, as thus expressed, ignores the fact that Mississippi is contractually bound to deliver only interruptible gas to its industrial customers. That is to say, delivery of interruptible gas to the industrial customers represents Mississippi's full "responsibilities to them." Furthermore, Mississippi's position is wholly out of harmony with the intent of the Act and with the fact that both the Commission and Mississippi have in the past recognized that Mississippi's sales to its industrial customers were not to have priority over sales to utility customers. Contracts executed by Mississippi in 1929 with utility customers gave preference to the requirements of domestic consumers over industrial consumers, in the event of shortage of gas, with the utilities to make every possible effort to increase sales to natural gas. Since that time the Commission has required, and Mississippi has accepted, restrictions on deliveries to its industrial consumers. In authorizing an increase from 135,000 Mcf to 183,000 Mcf in Mississippi's capacity on August 28, 1946, the Commission made it clear that all of Mississippi's capacity would eventually be devoted to utility sales unless Mississippi increased the capacity of its system from time to time as warranted by the increases in demand (*supra*, pp. 718–719). Moreover, Mid-South and certain other resale customers have had full requirements contracts with Mississippi dating back to 1929 and Laclede has had such a contract since 1950.

When the underbrush is cleared from Mississippi's plea in these proceedings, the Examiner finds that what it is really seeking is permission to avoid its responsibilities to utility customers which, for the most part, it voluntarily assumed, in order to more than meet its responsibilities to its industrial customers. And it is requesting that it be allowed to avoid its responsibilities to its utility customers at the same time it is refusing to expand its present system to provide for the requirements of all of its customers on an equitable basis.

Industrial sales, particularly interruptible sales, must be subordinated to utility sales, for the public interest can be protected in no other way. Furthermore, in considering Mississippi's above stated position the fact is not to be overlooked that Mississippi is acutely aware that its higher prosperity depends upon its ability to hold and increase industrial sales. There is, of course, no objection to such sales being made provided they are not made to the detriment of resale customers and the consuming public.

Mississippi's position in this proceeding is to be contrasted with the view expressed in *Pennsylvania Water & Power Co.* v. *Consolidated Gas Electric Light and Power Company of Baltimore*, 184 F. 2d 552, 567:

> One of the most important duties of a public utility, inherent in its franchise to serve the public, is the duty to take the initiative in * * * rendering adequate services, taking into account changing conditions; and the utility is not relieved from this duty because its activities are subject to governmental regulation, for a regulatory commission is not clothed with the responsibility or qualified to manage the utility's business. * * *

Here Mississippi is not only rendering inadequate service to its utility customers but is refusing to expand its existing system to provide their needs even though it knows that the expanded system would provide it with a reasonable rate of return on its investment. The catch is that Mississippi is demanding more than what the Commission regards as a reasonable rate of return for the

services it renders. Obviously in these circumstances the Commission has an obligation, within the limits of its authority, to cause Mississippi to properly perform its contractual obligations to its utility customers.

In its efforts to hold, promote and protect its industrial sales at the expense of its utility customers and the areas they serve, Mississippi is attempting to grab too great a place for its own pocketbook and is in effect dominating to a large extent the advancement and success of its utility customers. It appears that whether Mississippi will continue such domination will depend upon the extent to which the Commission utilizes its regulatory power under the Act, which is the blueprint for the Commission's work and which lays down the basic principles for the positive, constructive side of the Commission's task.

A problem which the circumstances of this case presents is the proper course a distributing company should pursue in overcoming the failure of its pipeline supplier, which favors its industrial sales, to live up to its contract obligation to "proceed with due diligence to install facilities or otherwise provide" the distributor with its total natural gas requirements. The course here being followed by Laclede in an effort to break out of its confinement is summarized by its president in the following testimony:

> Q. Tell me, Mr. Derrick, what is your position with respect to Mississippi's obligation to supply Laclede with its increasing gas needs?
>
> A. We believe that Mississippi * * * has the responsibility to make every reasonable effort to supply our actual gas requirements. But whatever the reason, Mississippi has failed to do so. We believe that in these circumstances we are entitled to seek the assistance of this Commission in increasing our stated demand if any of the gas is available on Mississippi's system and in modifying Mississippi's tariff to the extent that it will make it possible for us to take more gas without subjecting ourselves to the payment of outrageously high penalties.
>
> Q. Now, if Mississippi is not able or is unwilling to meet your requirements, then what do you plan to do?
>
> A. In that event we would feel that we have no alternative but to look elsewhere for part of the gas supply which we simply must have if we are going to continue meeting our public utility obligations to the people of St. Louis.

Laclede, like other gas distributing companies, is obligated to the extent possible to provide service to all those seeking service in its franchise area. This is an obligation that cannot be met merely by continuing to supply existing customers. The increased needs of existing customers as well as the requirements of new customers must be met. Thus, if Laclede and Mississippi's utility customers are to fulfill their public utility obligation they must obtain additional volumes of gas, including volumes of firm pipeline gas.

Solution to Problems Presented

Mississippi's utility customers need and are entitled to two things: (1) Increased stated demands. (2) Modification of Mississippi's FPC Gas Tariff to eliminate undue prejudice and disadvantage to the utility customers. Mississippi and its industrial customers oppose both. Their attack in large part centers upon the fact that Mississippi's present gas supply and facilities are inadequate to fill the demands of its utility and industrial customers, so that any increase in deliveries to the utility customers will diminish the gas supply now being made available to the industrials. Counsel for Mississippi seek to glean support for their position by arguing, *inter alia*, that the quantity limitations in Mississippi's industrial contracts have not been interpreted by either Mississippi

or the industrials as a binding limitation on the right of Mississippi to sell and the industrials to take more than that quantity. But this argument is beside the point. The question here is not what Mississippi and the industrials have regarded as permissible in the past but what the Act, public interest, and Mississippi's contractural obligations require for the future. As the undersigned Examiner stated in *Central Kentucky Natural Gas Co., et al.*, 15 FPC 700, 708–709, 719; aff'd 15 FPC 730; *Cincinnati Gas & Electric Co., et al.*, v. *F.P.C.*, 246 F. 2d 688–

> * * * events and situations are considered in relation to their causes and results. This makes it necessary for the Commission to deal not only with successive changes as they occur, but to utilize experience gained to more effectively deal with regulatory matters not involving change. Thus once it is demonstrated that practices and procedures are inappropriate for any reason, the Commission, having continuous jurisdiction, performs one of its primary functions in permitting or prescribing appropriate readjustments to provide a more stable basis for the continuous progress of the regulated industry. Stated another way, the Commission's orders are a necessary adjunct to carrying out the purposes of the statutes it administers and recognize that what once may have appeared to be an ideal regulatory action can be completely out of step with present and expected future conditions.
>
> * * * * * * *
>
> * * * In this situation, it is much better for the Commission to act in a timely way when a threat to economic stability appears on the horizon than to await the development of difficulties.

The only adequate solution to the problems here presented is for Mississippi to do what it could have already accomplished without perpetuating a worsening gas crisis in its service area, namely, *properly* provide the gas needed by its customers. The utility customers, without any apparent support from the industrials, have diligently sought to bring about this solution which Mississippi steadfastly rejects in the interest of the profitability of its industrial sales. Mississippi, therefore, gives the Commission no choice but to do the best it can in the circumstances of this case by strictly enforcing (1) the intent of Congress as reflected in the Act, and (2) the contractual rights of the parties. None of Mississippi's industrial customers have a contractual right to receive other than interruptible service and some of them are receiving service not authorized by the Commission. On the other hand, some of Mississippi's utility customers, including Laclede, its largest customer, have full requirements contracts and their natural gas requirements exceed that part of Mississippi's capacity not now allocated to them. Accordingly, for the Commission to carry out its regulatory functions in this case, it must allocate Mississippi's entire capacity to the utility customers, which have a superior right thereto, such allocation to be accomplished in two increments and to be accompanied by appropriate changes in Mississippi's FPC Gas Tariff. If before the second increment becomes effective next year Mississippi should desire to carry out its public utility responsibility and benefit the economy and the strength of its service area and the Nation by enlarging its existing system, rather than following the unnecessarily restrictive policy of insisting upon "The new subsidiary or nothing," the Commission can reconsider the action herein making the second increment effective.

Mississippi's largest utility customers take the position that their needs be provided through an expansion of Mississippi's existing transmission system rather than through Mississippi's proposal to create a subsidiary to contruct, own and operate a separate transmission system to promote and protect its industrial

sales. Expansion of Mississippi's system has provided Mississippi's customers with increased supplies of gas in the past. A further expansion can accomplish the needed result in the future. Moreover, expansion of Mississippi's system is the only way of assuring that both the utility and industrial services will be assigned their proportionate share of the cost, under a rolled-in rate method, for gas taken from Mississippi's system. That is to say, an expanded system with a rolled-in rate, rather than a separate system, serves the salutary function of equal treatment for all.

As already pointed out (*supra*, pp. 718–719), the Commission in authorizing Mississippi to increase its system capacity in 1946, stated that "For the peak day of 1950, it appears *that unless additional facilities are installed, almost 100 percent of the system sales capacity of 181,000 Mcf will be devoted to utility sales.*" But as the Commission also observed Mississippi "indicated its intention to add facilities to increase the capacity of its system from time to time as warranted by the increases in demands." That was in 1946 and until recently Mississippi has increased the capacity of its system from time to time, although such increases have not adequately provided for the needs of its customers. Now, however, Mississippi has gone on what is tantamount to a sit-down strike against additional gas supplies unless and until it has its own way of constructing a separate system. But Mississippi cannot go on such a strike and retain capacity not contractually committed to industrials from being allocated to utility customers depending upon Mississippi for their natural gas supply. Nor can Mississippi restrain any action of the Commission permitting other pipelines willing to provide additional service to the area from doing so.[8] The Commission has both the power and the obligation to act in this situation even if Mississippi desires to stand still.

As those familiar with the provisions of the Act know, the Commission has no power to compel a natural gas company such as Mississippi to enlarge its facilities for the purpose of providing additional service. But this does not render the Commission helpless in the circumstances of this case for it may at any time allocate a company's system capacity as the public interest may require provided such allocation does not impair the company's ability to render "adequate service" to its customers. The Examiner's order herein does not impair Mississippi's ability to render "adequate service" to industrial customers within the meaning of the Act, nor does it compel Mississippi to enlarge its existing facilities. Mississippi will be free to enlarge its facilities if it desires to furnish either firm service, or interruptible service in excess of present contract quantities, to its industrial customers, assuming the industrial customers are willing to continue to purchase gas on the terms offered by Mississippi. But if and when Mississippi applies for authority to enlarge its facilities the utility customers may and should intervene and assert their claim to any additional capacity applied for by Mississippi up to the extent of their then requirements.

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[8] The Commission's general authority to direct a second supplier to service an area already being served by another natural gas company is expressly reserved by Section 7(g) of the Act which provides that:

"Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural-gas company."

As the Court held in *Panhandle Eastern Pipe Line Co.* v. *F.P.C.*, 169 F. 2d 881, cert. den., 335 U.S. 854, "nothing in the * * * Act suggests that Congress thought monopoly better than competition or one source of supply better than two, or intended for any reason to give an existing supplier of natural gas for distribution in a particular community the privilege of furnishing an increased supply."

As has been shown (*supra*, pp. 717–721), Mississippi, with and without certificate authority, has increased its system capacity over the years without in each instance providing its resale customers with an opportunity to increase their stated demands, or to share in excess gas available on its system from time to time. The result is that a substantial part of Mississippi's capacity has been and is being used to supply the needs of new industrial customers and increased demands of industrial customers.

The Chief Executive Officer of Mississippi testified that "During the second World War we had about 65 million coincidental peak-day firm industrial gas load attached to our system. And that was the approximate volume in 1942, 1943, right through the War and after the War. That is what it is today." But much of Mississippi's capacity used in making industrial sales has been constructed without Commission authorization. For example, in 1952 the Commission allocated 35,000 Mcf, or only 8 percent, of Mississippi's then claimed capacity of 450,000 Mcf for industrial use, whereas the record shows that in the summer of 1952 Mississippi, without Commission authority or knowledge, increased its system sales capacity by some 50,000 Mcf, or to 500,000 Mcf. Today Mississippi's dependable system sales capacity is at least 534,000 Mcf, with the Commission, so far as the record shows, having authorized only 17,000 Mcf of the 84,000 Mcf difference between 450,000 Mcf and 534,000 Mcf (*supra*, p. 719). The portion (41,792 Mcf) of the 84,000 Mcf difference which has since been allocated to utility customers is hereinafter discussed (*infra*, pp. 732–733).

All changes in capacity are required by good conscience and the law to be disclosed at the time they take place. Discovery of the existence of unauthorized capacity increases and their unauthorized employment by Mississippi should result in the taking of affirmative steps by the Commission to assure that the unauthorized and discriminatory conduct exercised in the past will not be continued or repeated in the future.

Sales Capacity of Mississippi's System

In considering the sales capacity of Mississippi's system it should be pointed out that the section of its pipeline between Perryville station and Crossett station has 15,000 Mcf capacity for the delivery of gas to customers between those stations, which gas if not sold there cannot be moved beyond Crossett. Gas not sold between Crossett station and Neelyville and Poplar Bluff stations cannot be brought into the St. Louis area, and only a part of the gas not sold between those stations and the St. Louis area can be moved into that area. Thus Mississippi's witness Miller, in explaining his conclusion as to the system sales capacity testified that it—

> * * * is based upon a sales pattern in which some gas is sold between Perryville and Crossett, some sold between Crossett and Neelyville, some gas is sold between Neelyville and Bonne Terre and some gas is sold between Bonne Terre and the St. Louis area.
>
> Now there is no difficulty in changing the pattern so that more gas is sold near Perryville than was sold during the 1958–59 heating season, but the change cannot take place in the other direction, since the facilities do not exist to move more gas toward the St. Louis area.

Mention should also be made of the fact that Mississippi's Waterloo Storage Field, which began operation in 1950, has not measured up to expectations and it is not the kind of storage from which large volumes of gas can be taken day

after day.[9] Injections must be and are made as frequently as possible during the winter months. When full the Waterloo storage field contains about 450,000 Mcf.

Contrary to Mississippi's contentions, the Waterloo storage field is not to be ignored in determining the sustained dependable delivery capacity for stated demand purposes. For even though this field is not of the same seasonal character as other storage fields, it is useful and contributes to capacity. Commission witness Pettit, in reaching his conclusion as to the total daily system sales capacity, utilized an average daily withdrawal from Waterloo storage of 1,380 Mcf. According to his studies, the field has a daily delivery capacity of up to 18,000 Mcf.

It may also be observed in passing that Mississippi's witness Ziebold, whose testimony was concerned with the operation of Mississippi's system, testified that the difficulty experienced in system dispatching stems from the fact that Mississippi has no control over the daily takes of its industrial customers. Such customers have consistently overrun contract maximums during periods when utilities were manufacturing gas for peak shaving. The amount of their daily overruns has not been of any particular concern to the industrial customers since Mississippi's contracts with them do not contain either a minimum bill or provision for overrun penalty payment.

By use of Waterloo storage, withdrawal of line content and compressor overloads, Mississippi has been able to deliver for short periods of time larger quantities than what it regards as the design peak capacity (524,000 Mcf) and delivery capacity (531,000 Mcf) of its system. For example, the three consecutive days of highest system sales during the 1958–59 heating season occurred on February 18, 19 and 20, 1959. On the day of highest sales, February 18, sales totaled 555,785 Mcf, of which 19,680 Mcf was taken from Waterloo storage. The second highest day, February 19, had sales of 554,304 Mcf, of which 13,400 Mcf was taken from storage. The types of sales made on the three days are classified by Mississippi as follows:

	Feb. 18 (Mcf)	Feb. 19 (Mcf)	Feb. 20 (Mcf)
Interruptible industrial	39,486	35,049	34,611
Firm industrial [1]	61,086	65,147	61,332
Utility sales	455,213	454,108	452,039
Total	555,785	554,304	547,982

[1] As hereinabove explained (*supra*, p. 716), the so-called "firm" deliveries are in fact interruptible.

In connection with these particular sales it is to be borne in mind that they were made as the season was considered to be nearing its end and when Mississippi's operators thought they could reasonably protect themselves.

Mississippi's consecutive three day peaks in 1957–58 and 1958–59 averaged 544,000 Mcf and 551,000 Mcf, respectively. On four other groups of *three* consecutive days during the 1958–59 season, Mississippi's total sales averaged 541,000 Mcf (1/7/59–1/9/59), 539,000 Mcf (1/15/59–1/17/59), 542,000 Mcf (1/21/59–1/23/59) and 537,000 Mcf (2/10/59–2/12/59). On two periods of *five* consecutive days its sales averaged 542,000 Mcf (2/17/59–2/21/59) and

[9] As Commission witness Pettit explained, even though gas withdrawn from the Waterloo Storage Field, located just south of Mississippi's Columbia station, goes to the St. Louis area "it benefits everybody down the line."

538,000 Mcf (1/4/59–1/8/59). Mississippi's average deliveries on its *seven* consecutive day peak was 539,812 Mcf, with 457,340 Mcf delivered into the St. Louis area.

Counsel for Laclede and St. Charles contend that based upon past actual system performance over short periods of time the sustained delivery capacity of Mississippi's system, insofar as necessary to meet firm demands in the future, is not less than 540,000 Mcf per day. Assuming this 540,000 Mcf capacity the result would be:

	Mcf
Sales capacity	540,000
Deduct south of Crossett	15,000
Balance north of Crossett	525,000
Present stated demands north of Crossett	[1] 467,133
Balance	57,867

[1] Stated demand of 467,133 Mcf includes 640 Mcf for the City of Red Bud, Illinois.

Three witnesses testified with respect to the capacity of Misssissippi's system, two (Ziebold and Miller) being presented by Mississippi and the other (Pettit) by Commission counsel. The result of their testimony is shown by the following figures:

	Sales capacity (Mcf)	Deduct Crossett	Balance north of Crossett	Deduct stated demands	Balance
Ziebold	524,000	15,000	509,000	467,133	41,867
Miller	531,000	15,000	516,000	467,133	48,867
Pettit	534,000	15,000	519,000	467,133	51,867

As to deliveries into the St. Louis area the testimony of the three witnesses shows the following results:

	System (Mcf)	Deliverable into St. Louis area
Pettit	534,000	447,000
Miller	531,000	442,000
Ziebold	524,000	437,000

Mississippi, through the testimony of witness Miller (which was concerned with the capacity of Mississippi's system and the utilization of that capacity), would have any capacity determination based upon the unrealistic assumption that Mississippi's utility customers in the future will take their full stated demands on coincidental peak days and that they will take the full stated demands on every day of the heating season. However, this witness testified that he could recall no "instance where each customer, each utility customer, had his own individual peak simultaneously with the system peak and every individual customer's individual peak occurred on the same day."

Mississippi's system is about 88 percent efficient. Witness Ziebold testified that on his flow diagram, showing 524,000 Mcf per day system sales capacity,

he used the manufacturers rating on all the compressor stations on Line No. 2, although experience has shown that, except in at least one station, actual performance is above rated performance. As this witness testified, there isn't a day when the plant will not operate up to 12 hours at 110 to 115 percent of rated horsepower.

Commission witness Pettit, in making his study, took into consideration compressor overloading, which he explained as "nothing new," and use of line pack, an average net storage withdrawal of 1,380 Mcf,[10] compressor fuel and company use, line losses, the capacity of various sections of the line, manipulation of system operations and every other factor upon which a reliable judgment can be based. He examined considerable data on company operations for the 12-month period ending August 31, 1959 and studied the entire operations of the company during the 1958–59 winter period. After studying this data and inspecting certain compressor stations and other system equipment, as well as analyzing the data and testimony presented through witness Ziebold, particularly four sustained periods of high demand on Mississippi's system aggregating 33 days, namely December 8–15, 1958; January 2–12, 1959; January 30–February 5, 1959; and February 17–23, 1959, and based upon his long experience in pipeline design and operations, he concluded that the system has a daily sales capacity of 534,000 Mcf, of which 447,303 is deliverable into the St. Louis area. As witness Pettit testified, "I took Mr. Ziebold's periods * * * and I came out with an average."[11]

The Commission's witness Pettit looked at actual performance during a recent period as the most appropriate guide. To borrow the words of the Supreme Court in *New York Trust Co.* v. *Eisner*, 256 U.S. 345 and 349, he proceeded upon the valid assumption that "a page of history is worth a volume of logic" and on that page of history properly concluded that the system should be able to reach the same level of performance for future periods. The future, of course, will be aided by controlled takes by the industrials.

On the basis of the record the Examiner concludes that the sustained dependable delivery capacity for future stated demand purposes for Mississippi's utility customers is not less than 534,000 Mcf, of which not less than 447,303 is deliverable in the St. Louis area.

Allocation of System Capacity

The most recent allocation by the Commission concerning the sales capacity of Mississippi's system was in 1952 and 1953 when Mississippi claimed that its system capacity was 450,000 Mcf. At that time the Commission accepted a proposed settlement allocating 415,000 Mcf, or 92 percent, to Mississippi's utility customers, with the remaining 35,000 Mcf, or 8 percent, to be used by Mississippi in connection with its industrial sales. The sustained capacity of Mississippi's system today, however, is at least 534,000 Mcf, an increase of 84,000 Mcf, accomplished by Mississippi without further Commission authorization except for about 17,000 Mcf (*supra*, p. 719). As counsel for Laclede point out, Mississippi

[10] Mississippi made net storage injections during the 90-day period (December, January, and February) of over 60,000 Mcf, or an average daily injection of 670 Mcf. During this period it not only was able to replace the gas withdrawn during the 33 days of greatest demand, but injected 60,000 Mcf in addition. Witness Pettit's inclusion of 1,380 Mcf in his conclusion as to system capacity, as representing an average daily withdrawal from storage, therefore appears reasonable.

[11] Commission witness Pettit did not take the average deliveries during the highest periods, but rather the average of the entire 33 days during the several periods as the sustained capacity of the system.

> * * * has been able to retain a continuing volume of industrial sales in the range of 50,000–60,000 Mcf without at any time subjecting new or increased industrial sales to the test of comparative need *vis a vis* utility requirements. This means that the utilities have had no opportunity to assert their requirements against a substantial part of MRF's capacity. It may be that the new or increased industrial users could have established an overriding need for MRF's excess capacity superior to the long unsatisfied residential and commercial demand on MRF's system, our point is that they were never required to do so.

Counsel for St. Charles points out that if the Commission now allocates the 534,000 Mcf capacity in the same manner that the 450,000 Mcf capacity was allocated in 1952 and 1953, namely, 92 percent to the utility customers and 8 percent for industrial use, the result would be that 491,280 Mcf would be allocated to the utility customers and 42,720 Mcf would be allocated for industrial use. As he further states, however, since 1953 the stated demands allotted to Mississippi's utility customers have been increased by 51,792 Mcf, or from 415,000 Mcf to a total of 466,792 Mcf (*supra*, p. 715). This represents, under the 1952 and 1953 allocation, some 25,488 Mcf less to the utility customers than the 92 percent of the 84,000 Mcf of peak capacity added since 1953. Aside from this, of the 84,000 Mcf additional capacity, some 32,208 Mcf has never been allocated by the Commission, but has been and is being used by Mississippi to make deliveries upon an interruptible basis to its direct industrial customers.

Concerning the point made by counsel for St. Charles, counsel for Mississippi state that—

> * * * St. Charles advances the theory that in the 1953 rate settlement * * * there was an allocation of Mississippi's designed delivery capacity of 8% to the nonjurisdictional sales and 92% to the utility customers. The defect in this argument is that while the percentages are accurate the only allocation made was to assign 415,000 Mcf as a stated demand to the utility customers which assigned each such customer a maximum quantity. There was no allocation of any quantity either maximum or minimum to Mississippi for sales to its direct industrial customers. * * * The fact is therefore that the only allocation of capacity that has been made is that represented by the stated demands * * *. All the capacity in Mississippi's system not taken by the utility customers remains available for use by Mississippi in serving its industrial customers.

But the controlling point which counsel for Mississippi ignore is that gas not heretofore allocated by the Commission to specific customers can still be allocated by the Commission and, in the circumstances of this case, must now be allocated to specific utility customers. Mississippi can no longer be permitted to enjoy the luxury of the use of capacity not allocated to specific customers, for to permit a continuation of such enjoyment would not only nullify the provisions of Section 7(a) of the Act, insofar as Mississippi is concerned, but also the priority of Mississippi's responsibility to its utility customers which, as counsel for Laclede points out—

> * * * is clearly reflected both in its sales contracts and in its Tariff. Thus, its contracts with its industrial customers * * * are cancellable on six months' notice and contain maximum quantities limiting the lawful entitlement of each customer. Additionally, with one exception, MRF's firm industrial contracts expressly recognize in the following language or similar language, the priority to be accorded its utility sales [emphases supplied]:
>
> "Purchaser understands that the demands for natural gas which will be made upon Seller during the winter months by *the public utility distribution*

companies served by Seller may require substantially all of the natural gas which Seller will be able to transport through its pipeline system, and that Seller will give priority to those demands over the natural gas requirements of Seller's industrial customers. It is expressly understood and agreed that Seller does not guarantee to Purchaser a constant supply of gas, and *the delivery of gas to Purchaser will be curtailed from time to time and on occasion may be completely interrupted.* It is further expressly understood and agreed that Seller shall not be liable to Purchaser for any damage to Purchaser's plant, and equipment or any other loss which Purchaser may suffer as a result of any such interruption, curtailment or any failure of gas supply or service."

In contrast, Laclede's contract with MRF * * * is not subject to cancellation or interruption and obligates MRF to meet Laclede's full requirements, not merely its Stated Demand at any given time. Thus, MRF has a duty under this contract: (a) to make available to Laclede every foot of gas its present system can deliver to St. Louis and (b) to make every reasonable effort to expand its facilities and obtain additional gas supplies when and as necessary to meet Laclede's increased and growing requirements.

Similarly, Section 7 of the General Terms and Conditions of MRF's Tariff (Second Revised Sheet No. 14, Item F by reference) provides that, "firm service rendered by Seller to its buyers shall have priority over all other services rendered by Seller."

Hence, MRF's position, and that of its industrial customers frequently expressed in this proceeding, that its industrial sales are somehow entitled to a special preferred status is completely unfounded. * * *

Counsel for St. Charles contends that "Mississippi should be required, from capacity not heretofore allocated, to supply additional gas to St. Charles" requested in its Section 7(a) application herein. This could be done but more is required. What is plainly required is an allocation of the entire capacity of Mississippi's system to the utility customers except for 2,000 Mcf to provide pilot light service for industrial customers.

In connection with the Section 7(a) applications of St. Charles, Illinois Power and MidSouth, it may be pointed out that the Examiner had occasion to state in his decision in *City of Red Bud, Illinois, Docket No. G–16504*, issued July 25, 1960 that "adequate service," as that term is used in Section 7(a) of the Act, in the light of the circumstances and facts in this proceeding—

> * * * connotes the ability of Mississippi to satisfy the requirements of its utility customers every day throughout the year. It further connotes the ability of Mississippi to satisfy the requirements of all existing customers and those authorized by the Commission to be added throughout the year, except, if necessary, during peak periods. Deficiencies which may occur, if any, are to be met by industrial curtailment, which is the usual and normal practice in the industry * * *.
>
> * * * * * * *
>
> Mississippi's attempt to equate "adequate service" as that term is used in Section 7(a) with the demands of its industrial customers rather than to the volumes it is contractually obligated to deliver to them is wholly without merit. The order herein does not take gas away from anyone. It permits the maintenance of adequate service to existing customers, and provides the additional service which has been shown to be necessary and desirable in the public interest. This is an exercise of the Commission's prerogative under the Act to require service, making it impossible for Mississippi to veto the authority granted to the Commission.

As the Chief Executive Officer of Mississippi has recognized, the utility customers have been and will undoubtedly continue "to nibble away at" Mississippi's capacity not now allocated to the utility customers (*supra*, p. 716), which they may properly do under Section 7(a). There is, of course, no necessity for a continued nibbling away at such capacity if it is all allocated at one time so as to provide each of the utility customers their pro rata share. Obviously, what the Commission can do piecemeal it can accomplish in one action.

Accordingly, since the capacity of Mississippi's system is not less than 534,000 Mcf, this capacity less the present stated demands of 466,792 Mcf and 2,000 Mcf for pilot light service and 640 Mcf for the City of Red Bud, Illinois, or a balance of 64,568 Mcf is available for increasing the stated demands of the utility customers. One-half of the 64,568 Mcf, or 32,284 Mcf, is allocated to the present utility customers on a pro rata basis effective upon the date the order herein becomes the final order of the Commission. The remaining 32,284 Mcf is allocated to the utility customers on a pro rata basis effective December 1, 1961. Accordingly, the stated demands of Mississippi's utility customers are increased as follows:

Customer	Present stated demands (Mcf)	New stated demands (Mcf)	12-1-61 stated demands (Mcf)
Arkansas Lousiana Gas Company	12,900	13,792	14,684
City of Altheimer	400	428	455
City of Augusta	858	917	977
City of Chester	641	685	730
City of Hazen	456	488	519
Fort Smith Gas Corporation	2,700	2,887	3,074
Illinois Power	56,323	60,218	64,114
Laclede	330,000	352,823	375,647
MidSouth	22,790	24,366	25,942
Missouri Natural Gas Company	24,000	25,660	27,320
Public Utilities Company (Crossett, Ark.)	1,900	2,031	2,163
St. Charles	2,360	2,523	2,686
Town of Des Arc	415	444	472
Union Electric Company	10,000	10,692	11,383
Village of Dupo	675	722	768
Natural Gas Improvement District No. 2 of Ashley County, Arkansas	374	400	426
Total	466,792	499,076	531,360

Concerning the above referred to increased stated demands it should be observed here that not all of Mississippi's utility customers are parties to this proceeding, but the utility customers which are parties to this proceeding, in fairness to the other utility customers, seek only their pro rata share of whatever additional volume of gas is made available. If this procedure is not followed, the 64,567 Mcf would have to be allocated on a pro rata basis to each of the utility customers which are parties to this proceeding.

The Section 7(a) Applications

A. *Authority of the Commission*

A question has been raised concerning the propriety of the Commission's action denying Mississippi's motions requesting dismissal of the 7(a) applications of its existing customers—MidSouth, St. Charles and Illinois Power—for increased stated demands (21 FPC 814; 22 FPC 1081). In denying Mississippi's motions the Commission said "its review of the contentions, answer and Act shows that the clear language and intent of Section 7(a) gives the Commission jurisdiction

to hear and determine the matters involved." While the Commission's action, which is binding upon the Examiner, eliminates any necessity for consideration of this matter here, a brief discussion may serve to further point up the fact that the denial of the motions was well founded.

While the Commission's authority under Section 7(a) is sufficient to direct Mississippi to increase the stated demands of its existing utility customers, the circumstances of this case are such that the Commission may invoke the total of its statutory power, including its authority to allocate the ascertained dependable capacity of Mississippi's system, to accomplish the purposes which the statute makes mandatory.

The grounds upon which Mississippi's motions to dismiss were based are: (1) That there is no statutory authority for the filing of an application or other pleading by a gas distributing company for the purpose of obtaining an increase in stated demand. (2) That Section 7(a) of the Act is limited to gas distributing companies not already having natural gas service. (3) That the general terms and conditions of Mississippi's FPC Gas Tariff prescribe the method whereby additional quantities of gas may be obtained by a distributor from Mississippi. As to the latter contention it need only be observed that all provisions of the tariff are subject to the plenary power of the Commission under the appropriate provisions of the Act, including Section 7(a).

As shown by the order of the Commission issued February 6, 1959 (21 FPC 190; see note 12, *infra*), directing Mississippi to provide additional service to Illinois Power and St. Charles, and initial service to the City of Chester, Illinois, and prior decisions (19 FPC 143, 148–150; 10 FPC 369, 385–387), the Commission has consistently held that its authority under Section 7(a) to order a pipeline supplier to provide increased deliveries to its utility customers is coextensive with its authority to direct initial services to a new customer. In Wisconsin *Southern Gas Company*, 4 FPC 188, 191, the Commission stated:

> Under section 7(a) we "*may*" by order "direct" a natural gas company to extend its service if such action is found to be "necessary or desirable in the public interest." From an examination of the language of this section, it is apparent, that Congress vested in the Commission broad discretion in dealing with cases involving the exercise of authority to require the extention and connection of facilities *and the rendition of additional service.* [Emphasis supplied.]

One additional citation of authority, *Home Gas Company* v. *F.P.C.*, 231 F. 2d 253, *cert.* den., 352 U.S. 831, will suffice for the purpose of showing the authority of the Commission with reference to 7(a) applications. In the *Home Gas Company* case the Court rejected the contention that the Commission, under Section 7(a) of the Act, was powerless to order Tennessee Gas Transmission Company, in a Section 7(c) proceeding, to provide additional service. In this case the Court sustained the order of the Commission directing Tennessee to supply two distributing companies with a supplementary supply of natural gas in addition to the supply then being furnished by Home Gas Company (also by Algonquin Gas Company as to one of the distributors). The distributors showed, *inter alia*, that a connection with Tennessee's system was necessary for the normal development of their gas businesses then undergoing tremendous growth in demand for natural gas service; that they had no assurance that the additional gas needed by them could or would be made available by their then pipeline suppliers; that there would be an improvement in the adequacy and reliability of service to their customers; that they would realize substantial economies through lower gas cost and retirement of old standby emergency equipment; that they could develop markets that could not otherwise be developed; and their purchase of gas from

Tennessee was the most feasible and economical solution of their gas supply problem. In rejecting Home's contention that the Commission was powerless to order Tennessee to provide additional service under Section 7(a) to the distributors, which were customers of Home, the Court said (231 F. 2d at 257–258):

> * * * Petitioners contend that, assuming the Commission has power under the Act, 15 U.S.C.A. § 717f (a), (e) and (g), to grant a certificate * * * to a second supplier for service to an area already being served, the Commission has no power to require such service by order pursuant to § 717f(a) * * *.
>
> To uphold petitioners' contention would in effect force us to consider the above-noted sections as being mutually exclusive. This we cannot do. Indeed, we find them complementary. No basis exists in the legislative history of the Act, and certainly none in the plain language of the text, for the creation of a third limitation in § 717f(a), as petitioners urge, namely, where the area involved is already being served by a natural gas company. Cf. *Manufacturers Light & Heat Co.* v. *F.P.C.*, * * * 206 F. 2d 404.

Since the Commission, under Section 7(a) of the Act, may require a second supplier to provide supplementary service to a distributor as the public interest may require, it necessarily follows that it may require a supplier to do the same thing with respect to its existing utility customers, provided such action places no undue burden upon the supplier or impairs its ability to render adequate service to its customers. The "adequate service" here referred to is that represented by maximum contract or tariff obligation authorized by the Commission, not excess deliveries, at the pleasure of the supplier, to a particular customer or group of customers.

Moreover, the Commission may at any time allocate to a specific customer or customers any unallocated capacity in a pipeline system. Such allocation authority may not be delegated to or assumed by the management of a pipeline, for the exercise thereof is entrusted solely to the Commission. As held in *Central West Utility Co.* v. *F.P.C.*, 236 F. 2d 287, 288:

> * * * it is the duty of the Commission to determine the present capacity of the Liberty Lateral or its original designed or actual capacity, whichever was greater and allocate the gas to be delivered from the lateral within the maximum capacity thus ascertained. * * *

And it is well known, of course, that, as recognized in *Federal Trade Commission* v. *Bunte*, 321 U.S. 349, 352, "Authority actually granted by Congress * * * can not evaporate through lack of administrative exercise."

B. *The 7(a) Dockets*

The dockets covering the 7(a) applications filed by Illinois Power, MidSouth and St. Charles are:

> *Docket No. G–17984.* Application filed March 5, 1959, by Illinois Power for an additional 12,000 Mcf which, together with the quantities heretofore authorized (57,202 Mcf), would give it 62,202 Mcf stated demand.[13]

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[13] Illinois Power's service agreement with Mississippi expired in 1951. It has, however, been authorized by the Commission to purchase 55,000 Mcf per day of gas from Mississippi under Mississippi's existing rate schedules. On February 6, 1959, the Commission directed Mississippi to deliver an additional 2,202 Mcf of gas per day to Illinois Power for service in the communities of O'Fallon, Hamel, and Millstadt, Illinois, and to file executed service agreements covering this service (21 FPC 190, 197). In the same order the Commission directed Mississippi to sell and deliver to St. Charles an additional daily volume of 360 Mcf and to provide initial service to the City of Chester, Illinois, *i.e.*, a maximum daily volume of 1,518 Mcf and to file executed service agreements covering such service.

Docket No. G–17567. Application filed January 19, 1959 by MidSouth for an increase in its present daily delivery volume of 22,790 Mcf to 25,790 Mcf by November 1, 1960.

Docket No. G–18405. Application filed April 28, 1959 by St. Charles, with a present stated demand of 2,360, for successive annual increases reaching a total stated demand of 5,651 Mcf by November 1, 1963.

Staff counsel agree that the 7(a) applicants have fully sustained the burden of proof, including the fact that Mississippi has unallocated capacity greatly in excess of what the 7(a) applicants seek. However, in lieu of granting the increases in stated demand the staff recommends that the Commission require Mississippi to make certain tariff changes. Such changes, however, would provide only token relief to the 7(a) applicants.

The record fully substantiates the requests made by Illinois Power, MidSouth and St. Charles for additional supplies of natural gas and, to the extent possible through a pro rata allocation of Mississippi's present unallocated capacity, those requests have been granted. In view of this the Examiner finds it unnecessary to consider the 7(a) applications in detail other than to discuss certain contentions raised with respect to MidSouth's application.

MidSouth is a full requirements customer of Mississippi. Many of the communities served by it have never used anything but natural gas. As staff counsel recognize, MidSouth is "sorely" in need of the additional 3,000 Mcf it seeks "to meet the requirements of *domestic* customers *now* actually attached."

Mississippi is MidSouth's most feasible source of supply. No known storage possibilities exist in MidSouth's service area. Its use of peak shaving equipment on a reasonable basis is complicated by the fact that it serves eighteen communities and purchases gas from Mississippi at seventeen separate delivery points. Studies made by MidSouth of peak shaving devices have shown the cost thereof to be of an exorbitant nature.

In resisting MidSouth's request for additional gas, counsel for Mississippi state in their brief that—

> Due to the location of the several communities constituting MidSouth's system it is apparent that whatever gas MidSouth wants it is in a position to take. The record is clear that the management of that Company will continue as in the past to take on all the residential space heating business it is offered and intends to take overrun gas so long as the cost of gas purchased from Mississippi does not exceed what gas from other sources would cost.

MidSouth, however, is simply fulfilling its public utility responsibility. Its efforts in that direction can provide no comfort to Mississippi in its failure to live up to its obligation to provide MidSouth's full natural gas requirements. No company should want, or be permitted, to stand still when the public interest demands otherwise. The pressure to grow is always a vital force and in business life growth is taken as a matter of course. Unless a business is prepared to take risks and expand it will soon find itself pushed aside as more venturesome competitors take its place. Moreover, a cardinal principle in the industry should be that every utility provided new increments of gas at the lowest possible cost. As the United States Court of Appeals for the Fifth Circuit pointed out in its decision issued August 2, 1960, in *El Paso Natural Gas Company, et al. v. Federal Power Commission*, "It is the obligation of all regulated public utilities to operate with all reasonable economies."

MidSouth now has a stated demand of 22,790 Mcf per day, such volume being assigned to it in 1953. On its 1955–56 peak day it took 21,591 Mcf. Its 1956–57

peak day take was 23,693 Mcf. Its 1957–58 peak day take was 24,383 Mcf. Its 1958–59 peak day take was 26,107 Mcf, or 3,317 Mcf more than its present stated demand. This 3,317 Mcf overrun is 317 Mcf in excess of the 3,000 Mcf increase sought by MidSouth in this proceeding.

Mississippi knows that MidSouth must take overrun gas to meet its requirements. It is also aware of the fact that on every day that MidSouth was taking overrun gas in the 1958–59 heating season and paying a penalty therefor, Mississippi was selling gas in excess of contract volumes to its interruptible customers without penalty.[13] True it is, as counsel for Mississippi say, "that whatever gas MidSouth wants it is in a position to take," but the point is that in the circumstances of this case it should be permitted to take it without penalty. Failure to increase MidSouth's stated demand would simply enable Mississippi to continue to exact what is tantamount to an unjust and unreasonable charge for the service it is contractually obligated to render and can render without in any way impairing service it is obligated to render to other customers.

MidSouth's deliveries to its interruptible customers are fully interruptible, except for one customer which used only 28 Mcf on the 1958–59 peak day. During the 1958–59 heating season MidSouth curtailed deliveries to its interruptible industrial customers on 48 days.

In connection with MidSouth's request for a 3,000 Mcf increase in its stated demand it may be pointed out that Mississippi River Chemical Company (Chemical Company), formerly a division of Mississippi, is located about 35 miles south of the St. Louis area and its contract with Mississippi provides for interruptible deliveries. The plant has standby fuel and can be fully interrupted. But notwithstanding this fact, Chemical Company never received less than 5,726 Mcf on any day during the 1957–58 heating season. For the year 1958 Mississippi's sales to Chemical Company averaged 9,670 Mcf per day. The records show that if deliveries to Chemical Company were interrupted at least part of this gas could not be delivered to the St. Louis area on some days and other days none of it could be delivered into St. Louis.

A witness for Mississippi estimated that under the best operating conditions approximately half of the gas curtailed at the Chemical Company plant might be moved into the St. Louis area but that 100 percent thereof could be delivered to MidSouth. It is thus apparent that counsel for MidSouth correctly conclude that "Separate and apart from Mississippi's ability to render increased service to MidSouth from unallocated system capacity, the evidence of record shows that Mississippi can make additional deliveries to MidSouth of gas which could not be delivered to the St. Louis area on peak days."

Service Rendered by Mississippi to Its Industrial Customers

Although each of Mississippi's contracts with its industrial customers provides for interrupting service to such customers, Mississippi nevertheless regards some of the industrials as firm customers, they being referred to in this

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[13] As Staff counsel state in their brief, "During the heating season of 1958–1959, St. Charles was forced to pay the penalty for 'substantial' volumes of excess gas * * *, MidSouth had to make penalty payments for ten days on which it exceeded its Stated Demand * * *, and Missouri Natural made penalty payments for six days on which it exceeded its Stated Demand * * *. The significant fact is that on every day on which these utility customers were taking overrun gas, and paying a penalty for the same, Mississippi was selling gas in excess of the contract volumes to its 'firm-interruptible' customers * * *."

proceeding as "firm-interruptible" customers. As explained by a witness for Mississippi:

> Q. Well, now, do you consider all your firm industrial customers to be "firm-interruptible"?
>
> A. When it is necessary to interrupt them, yes. We don't plan it that way. * * * We don't want to curtail them. We oppose the 7(a)s because it creates a situation that leads to that curtailment. If we have to curtail them to meet the utility load we do.

Mississippi not only has "firm-interruptible" and what are said to be "true" interruptible direct sales, but it has in addition "top of the totem pole" interruptible direct sales which are made to customers willing to pay 50 cents per Mcf for gas so that, should any curtailment occur, they will be the last curtailed. A witness for Mississippi testified:

> The WITNESS: The 50 cents is interruptible gas.
>
> PRESIDING EXAMINER: Yes. But it is, as * * * you agreed at the top of the totem pole, so to speak.
>
> The WITNESS: Yes, that is right.

The present provisions of Mississippi's FPC Gas Tariff enable Mississippi to make available to its industrial customers all gas not taken by the utilities. This means that Mississippi has been making available to its industrial customers that part of the 466,792 Mcf not at times being utilized by the utility customers, plus the difference between the present stated demands and the total capacity of the system. The industrial customers, therefore, take their total requirements up to the capacity of Mississippi's system to deliver. That is to say, except as they may, or some of them may, at times be limited in their takes by the capacity of Mississippi's system, the industrial customers take as much or as little gas as they need on any day, this being permitted by the lack of any contract minimum bill or overrun penalty. On the other hand, the utility customers not only pay a minimum bill but a substantial penalty for takes in excess of stated demand. The heavy overrun penalty applicable to utility customers and the failure of the tariff to make provision, as is the case with respect to other suppliers, for the utility customers to share in excess gas available on Mississippi's system, have the practical effect of assuring the industrial customers that there is available for their use at all times substantially all gas on Mississippi's system in excess of stated demands, as well as that part of the stated demands not taken by the utilities from time to time.

On any day that Mississippi is unable to deliver to one of its "firm-interruptible" customers all the gas it could have used on that day—regardless of its maximum contract volume—Mississippi considers that that customer has been "curtailed". As a witness for Mississippi put it, "Curtailment to us means anything that is cut by our request below the volume that they would actually need on the day that the curtailment takes place." He further explained: "Naturally when we start curtailing we curtail the lowest price gas first and work our way up to the highest price, and vice versa when we are putting the gas back on." Operating on this basis Mississippi considers that during the 1958–59 heating season it curtailed some of its "firm-interruptible" customers on five days, yet on those same days it was delivering over the contract maximum volumes to other of such customers and even selling some gas to what it regards as "true" interruptible customers.

The instability of what Mississippi conceives to be requirements is further strikingly illustrated by its continually changing "requirements". As counsel for Laclede point out, Mississippi "has employed an 'allocation' system in apportioning firm industrial gas, which has permitted an industrial customer to

increase its entitlement during peak periods simply by using more gas during off-peak periods, thereby building up its quota or 'credit' in the preceding month * * *."

Mississippi's Objections to Regulation of Its Industrial Sales

Mississippi objects to Commission regulation of its industrial sales on four grounds: (1) That the Commission has no statutory juridiction over direct sales to industries. (2) That there cannot be a violation of the anti-discrimination provisions of Section 4(b) by reason of its industrial sales. (3) That the "Grandfather Clause" contained in the proviso of Section 7(c) of the Act gave it the right to serve the industrial customers it was serving on February 7, 1942, untrammeled by Commission regulation. (4) That the right acquired under the "Grandfather Clause" enables it to serve today, without regulation, a volume of gas equal to that which it sold on February 7, 1942, and such volume may be sold to any industrial customer or customers of its choice along the route of its pipeline.

It is obvious, of course, that if Mississippi's contentions as to the want of authority in the Commission to regulate its industrial service were to be sustained, it would pave the way for it to justify unauthorized construction of facilities to serve some of its industrial customers; the taking on of new industrial customers without authorization; the supply of increased demands to industrials; and continued discrimination against its utility customers.[14]

Contention (1). Concerning the contention that the Commission has no statutory jurisdiction over direct sales to industries, it is true that the Commission's jurisdiction does not extend to rates charged for direct sales made by a pipeline (*Panhandle Eastern Pipe Line Co.* v. *P.S.C. of Indiana*, 332 U.S. 507; *City of Hastings, Nebraska* v. *F.P.C.*, 221 F. 2d 31, *cert.* den. 349 U.S. 920). However, the Commission's jurisdiction does extend to the transportation of gas for the direct sales (*Panhandle Eastern Pipe Line Co.* v. *F.P.C.*, 232 F. 2d 467, *cert.* den., 352 U.S. 891). The fundamental distinction which the Act makes between resale and direct sales services does not, therefore, make the direct *service* immune from regulation, the intent of the statute being that each service is to be "regulated in a different manner and for different purposes" (Order issued June 13, 1960, *South Georgia Natural Gas Co., Docket No. G-17568*, 23 FPC 795). There is, of course, no complaint here of discrimination in the rates governing sales to the two classes of customers. Rather, as counsel for Laclede put it, the objection is "to the fact that excess gas *service* is supplied to the direct sale customers but *not to the utilities*, which may have a preferential right to it. Laclede complains, in other words, that MRF uses its *transportation facilities* in a discriminatory manner proscribed by Section 4(b)—not that it *sells* gas to one of two classes of customers at a discriminatory rate proscribed by Section 4(a)."

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[14] As counsel for Laclede state, "The record herein shows that, over the past ten years, MRF's industrial service has, for reasons which are not entirely clear, largely escaped Commission surveillance. In contrast to other pipelines, Mississippi, through circumstance or design, has been able to avoid normal Commission regulation of the commencement, abandonment, volume and character of its industrial service. The record shows conclusively that MRF has increased its capacity, has taken on new industrial customers and has changed the volumes supplied to individual industrial customers without Commission authorization. As a result, while a part of MRF's jurisdictional service (its utility sales) has been limited by inadequate Stated Demands and severe penalties for overruns, another part (its industrial service) has been entirely free of any service limitations except for the priority accorded utility Stated Demands."

Contention (*2*). To be just and reasonable within the meaning of the Act a tariff applicable to a pipeline's utility customers must satisfy at least two broad principles. First, it must produce fair results between the supplier and its customers. Second, it must not unduly discriminate against any customer or class of customers in favor of any other customer or class of customers. Mississippi's existing tariff does not satisfy the latter principle. That discrimination of the type now permitted by that tariff is prohibited by Section 4(b) of the Act is a question to which the Court addressed itself in *Panhandle Eastern Pipe Line Co.* v. *F.P.C.*, 232 F. 2d 467, *cert.* den., 352 U.S. 891, and decided adversely to Mississippi's contention, this being shown in the excerpt from that opinion set forth below (pp. 743–744).

Contentions (*3*) *and* (*4*). Mississppi contends that the "Grandfather Clause" contained in the proviso of Section 7(c) of the Act gave it the right to serve the industrial customers it was serving on February 7, 1942, untrammeled by Commission regulation, and that the right so acquired enables it to serve today, without regulation, a volume of gas equal to that which it sold on February 7, 1942, and that such volume may be sold to any industrial customer or customers of its choice along the route of its pipeline.

Mississippi's position with reference to its "grandfather" rights ignores the fact that Congress, in enacting the Act, embarked upon a program of regulation through Commission control of its operations. Mississippi's plea for self-regulation as to all aspects of its industrial business is therefore wholly untenable. Moreover, no public utility may pick and choose customers it finds most profitable without regard to the overall public interest (*United Fuel Gas Co.* v. *Railroad Commission of Kentucky*, 278 U.S. 300, 309; *Manufacturers Light & Heat Co.* v. *F.P.C.*, 206 F. 2d 404, 408).

The law with respect to Mississippi's contentions is so settled as not to merit discussion, but in view of the seriousness with which these contentions are asserted they will be considered. In doing so, however, the fact should be made clear that Mississippi's position incorrectly assumes that its service to existing direct customers is provided under its "grandfather" certificate. The fact is that some of Mississippi's direct sale customers were not served on February 7, 1942, the effective date of its "grandfather'" certificate. A substantial portion of its existing direct service is therefore "nongrandfather" because it is supplied new customers and involves increased deliveries. Merely because Mississippi supplies gas to new customers in its "grandfather'" area or increased volumes to old customers, does not mean that such service comes within the scope of its "grandfather" certificate (*Kansas-Nebraska Natural Gas Co.*, 6 FPC 259, 265–266). As the Commission only recently had occasion to again make clear, changed and increased deliveries make necessary new certificate authority. (See order issued June 13, 1960, *South Georgia Natural Gas Company*, Docket No. G–17568.)

If it were true that the "grandfather" certificate authorized Mississippi to continue wholly unrestricted and unregulated service to its industrial customers, Mississippi would have the same rights regarding its utility "grandfather" sales and service. Clearly this is not the case. As held in *Mississippi River Fuel Corp.* v. *F.P.C.*, 121 F. 2d 159, 163, service contracts, even though entered into prior to the enactment of the statute, are subject to regulation under the Act:

> It is argued that petitioner's contracts were entered into some years before the legislative enactment, and hence, they must be held inviolate against statutory regulation. Having held the statute a constitutional regulation of "an industry * * * subject to control for the public good" (*Nebbia* v. *New York*, *supra*), it logically follows that contracts made by petitioner,

even though prior to its enactment, are also subject to regulation in the public interest. *Union Dry Goods Co.* v. *Georgia Public Service Corp.*, 248 U.S. 372 * * *.

Mississippi's "grandfather" certificate authorized the continued operation of its "facilities, which were in *bona fide* operation on February 7, 1942, * * * for the transportation and sale of natural gas, subject to the jurisdiction of the Commission" (4 FPC 535). Such certificate was, however, issued

> * * * without prejudice to the authority of this Commission * * * with respect to rates, service, accounts, valuation, estimate or determination of cost, or any other matter whatsoever now pending of which may come before this Commission * * * (Paragraph B).

By inserting this provision in the order the Commission made sure its intent, and that of the Act, could not be mistaken. The Commission here clearly recognized that the "grandfather" certificate merely authorized the "continued operation of" facilities, leaving the results of operation, changes in service, addition of facilities, abandonments, etc., to the future regulatory control of the Commission. Indeed the Commission could not have granted broader authority to Mississippi insofar as that certificate was concerned for the provisions of the Act regulate service initiated both before and after February 7, 1942, in identical fashion. "A 'grandfather' certificate obviously is not intended to be unlimited but, rather is subject to future regulation, under the provisions of the * * * Act." *Michigan-Wisconsin Pipeline Co.*, 6 FPC 58, 63, aff'd *Panhandle Eastern Pipeline Co.* v. *F.P.C.*, 169 F. 2d 881; *Kansas-Nebraska Natural Gas Co.*, 6 FPC 259, 265–266.

The Examiner must therefore reject Mississippi's contention that its transportation facilities, insofar as they are used in making any direct sale in the general area of its "grandfather" certificate, are beyond the reach of the Commission's regulatory power. That contention is at variance with the plain requirements of the Act and is at war with Mississippi's prior recognition and acceptance of the Commission's regulatory authority relating to service rendered in its "grandfather" area. For example, Mississippi's emergency service rules, effective November 1, 1950 (9 FPC 219), required Mississippi to restrict deliveries to its "grandfather" industrial customers. Moreover, the 7(a) applications granted by the Commission from time to time since the issuance of the "grandfather" certificate have had the effect of restricting deliveries to Mississippi's direct customers. Then, too, the Commission often sets volumetric limits on the industrial service of pipelines such as Panhandle Eastern Pipeline Company which made substantial direct sales prior to 1942. And as the court held in *Panhandle Eastern Pipe Line Company*, v. *F.P.C.*, 232 F. 2d 467, *cert.* den., 352 U.S. 891; it is within the Commission's power to order Panhandle to make excess gas available to its utility customers to prevent undue discrimination:

> * * * When the Congress gave the Commission control over the transportation of natural gas, it necessarily gave it control over the functioning of a pipeline's facilities. Since these are limited, new services must be subject to the Commission's authority if the latter is to be at all effective. Otherwise the Commission would be unable to enforce the mandate of Section 4(b) of the Act, * * * and a natural gas company, contrary to the there declared principles of the Act, would be able to "(1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service."

If the orders on review had failed to limit the priorities of interruptible service for direct sales to those available for the resale customers, Panhandle, by allowing higher priorities to its direct sale purchasers who constitute only 6% of its total volumes of business, could preempt the entire interruptible capacity and leave the resale group without any of the excess gas at all. The resale buyers, saddled as they are with most of the cost of construction and maintenance of the transportation facility, are entitled to a reasonable amount of the I Schedule gas. This is the intent and accomplishment of the orders.

* * * * * * * * * The Commission by those orders is insisting that the petitioner properly perform its obligation to its existing customers. It is refusing to allow petitioner to avoid its responsibilities in that regard by selling all of its interruptible capacity directly to industry to the detriment of its resale customers and the consuming public. The control exercised is an integral part of the Commission's jurisdiction over the transportation of natural gas.

Tariff Revisions

Evidence offered by Commission counsel shows that Mississippi's system capacity is at least 534,000 Mcf, or 10,000 Mcf per day greater than the 524,000 Mcf claimed by Mississippi, and this excess amount is without giving consideration to curtailing any industrial customers to the amounts set forth in their respective interruptible gas service contracts.

It is the theory of the Commission Staff that, so far as capacity is concerned, only the 10,000 Mcf referred to in the preceding paragraph is available for use by Mississippi's utility customers. However, in their view, no part of the 10,000 Mcf should be used to increase the stated demands of the utility customers. Their position is that the 10,000 Mcf would be utilized completely in the administration of the revised tariff provisions which they propose. The Examiner does not agree with either the theory or position taken by staff counsel.

Mississippi's FPC Gas Tariff permitted authorized overruns of only 1 percent of the stated demands of 1,000 Mcf, whichever is the greater, and even within that narrow limit there is a penalty provision with respect thereto. That is to say, if a utility customer does not overrun its stated demand more than five days in any one month or two days in succession, the penalty is $0.15 per Mcf. Otherwise, the penalty is $2.00 per Mcf. For all gas over the 1 percent (or 1,000 Mcf) limitation, the penalty is $10.00. As counsel for Laclede state, "Although in theory the utilities may be able to take excess gas to meet emergency demands, in actuality they cannot in most instances afford to pay the $10.00 per Mcf penalty rate, which is imposed regardless of the availability of the gas on" Mississippi's system. They further point out that "Because of the size of Laclede's take from its eight delivery points, any overrun would almost inevitably exceed the 1,000 Mcf 'first step' of $2.00 gas and go into the $10.00 penalty gas step in MRF's existing tariff. An overrun of only 5% of Laclede's stated demand would result in a penalty of approximately $157,000.00 a day!

Laclede takes gas from Mississippi at eight metering points. It also makes certain sales directly off Mississippi's line. Since there is a substantial delay in obtaining complete metering readings and since there are unavoidable limitations in metering accuracy, Laclede, should it attempt to take its entire stated demand of 330,000 Mcf, would never have any positive assurance that it would not incur the overrun penalty of $10.00 per Mcf for such gas as it might inadvertently take in excess of its stated demand. As counsel for Laclede state,

"During the 1958–1959 season, for example, Laclede never on any day took its full stated demand, although it manufactured gas or made net withdrawals from storage on 35 days of the season * * *. MRF's existing Tariff, therefore, not only prevents Laclede and the other utilities from sharing in the excess gas available from time to time on its system but it also effectively prevents them from taking the full amount of gas to which they are justly entitled." During the 1958–59 heating season Laclede was able to come within 3,000 Mcf of its stated demand on only three days. It took less than 325,000 Mcf on all but 19 days.

Staff counsel, recognizing the inequitable and discriminatory operation of Mississippi's overrun provision, recommends that Mississippi be directed to file a revision of its Fourth Revised Sheet No. 6, Section 6(a), which would apply the existing overrun takes only to the extent that they exceed 2 percent of the stated demand. Such a penalty revision, which is adopted by the Examiner, would permit Laclede and Illinois Power to come close to taking their stated demand without fear of having to pay the $10.00 penalty for overrun gas. Contrary to the position of Commission counsel, this liberalized tariff provision is no justification for not allocating presently unallocated capacity to Mississippi's utility customers. This is made abundantly clear by counsel for Illinois Power—

> * * * It is the theory of the Commission Staff * * * that this 10,000 Mcf of gas would be utilized completely in the administration of the revised tariff provisions proposed by the Staff. With all due deference, Illinois Power suggests that this would not necessarily be the case. The penalty provisions—although liberalized from those existing at the present time and although desirable in themselves as additions to Mississippi's FPC gas tariff—are not such as will permit a utility, such as Illinois Power, to purchase gas intentionally above its stated demand. The same unreliability of telemetering equipment that now prevents a utility from approaching its existing stated demand will preclude its going above its stated demand intentionally, even under the liberalized penalty provisions proposed by Commission Staff. Thus, the utility companies will attempt to buy 100 percent of their stated demands and, if they inadvertently run over such stated demands, they will not be saddled with a prohibitive penalty if their overrun does not exceed 2 percent of the stated demand. But any overrun greater than 2 percent would be prohibitive and uneconomical for the utility companies to assume—i.e., $2.00 per Mcf for each Mcf in excess of the stated demand up to 3 percent, and $5.00 per Mcf for each Mcf in excess of 3 percent. We submit that even during coincidental peak days the total takes by the utility companies from Mississippi will not call for an invasion of the 10,000 Mcf of excess gas found to exist in Mississippi's system. * * *

Two other revisions in Mississippi's existing tariff are also necessary and desirable in the public interest. The first is a revision to Section 11(b), First Revised Sheet No. 16, as requested by Laclede, to provide that any buyer whose gas requirements have not been met by Mississippi will remain a general service buyer under the F–1 Rate Schedule if it obtains gas from elsewhere. The second is a revision of F–1 Rate Schedule, or the addition of a new Tariff Sheet, to provide for the sale of E or excess gas to Mississippi's utility customers which may be available on Mississippi's system from time to time, such excess gas to be sold the utility customers in proportion to their effective stated demands. As already pointed out, Mississippi's present tariff discriminates against the utility customers in that it permits Mississippi to sell all of its excess capacity to its industrial customers, a practice which is inconsistent with the Act and the requirements of the Commission as to other pipelines.

FINDINGS

(1) Mississippi, having its principal place of business at St. Louis, Missouri, owns and operates a natural gas transmission pipeline system located in the States of Texas, Louisiana, Arkansas, Missouri and Illinois, and by such operations Mississippi is engaged in the transportation and sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission, and is, therefore, a natural-gas company within the meaning of the Act as found by the Commission in its order of March 1, 1944, Docket No. G–291, 4 FPC 535.

(2) Laclede, Illinois Power, MidSouth, St. Charles, Union Electric Company and Missouri Natural Gas Company, each is a person engaged in the local distribution of natural gas to the public and each purchases natural gas from Mississippi for resale for ultimate public consumption under the terms and provisions of Mississippi's FPC Gas Tariff, Original Volume No. 1.

(3) MidSouth, Illinois Power and St. Charles each have filed an application under Section 7(a) of the Act; Laclede, Union Electric Company and Missouri Natural Gas Company have each filed intervening petitions in said 7(a) applications; and Laclede has filed a complaint upon which the Commission has instituted an investigation. Each of these proceedings is directed against Mississippi and seeks an increase in the stated demand of each which is now in effect in Mississippi's FPC Gas Tariff, Original Volume No. 1, 10th Revised Sheet No. 25, and seeks certain revisions of the terms and provisions of Mississippi's said FPC Gas Tariff, Original Volume No. 1.

(4) Increasing the stated demands of each of Mississippi's utility customers, to the extent and in the manner provided in paragraph (A) below, will not place an undue burden upon Mississippi and will not impair its ability to render adequate service to its customers.

(5) Mississippi shall continue to sell and to deliver natural gas to each of its utility customers, such sale and delivery to be henceforth on the basis of the stated demands set forth in paragraph (A) below.

(6) It is necessary and desirable in the public interest that Mississippi make the following changes in or additions to its FPC Gas Tariff Original Volume No. 1:

(a) A revision of Section 11(b), First Revised Sheet No. 16, to provide that any buyer whose gas requirements have not been met by Mississippi will remain a general service buyer under the F–1 Rate Schedule if it obtains gas elsewhere.

(b) A revision of F–1 Rate Schedule, or the addition of a new Tariff Sheet, to provide for the sale of E or excess gas which may be available on Mississippi's system from time to time, such excess gas to be sold to the F–1 customers in proportion to their then effective stated demands. Excess gas rejected by any F–1 Rate Schedule buyer will be apportioned equitably among the remaining F–1 buyers desiring to purchase such excess.

(c) A revision to Section 6 of Rate Schedule F–1 which will provide that for each day that a buyer exceeds its stated demand by not more than 2 percent or 1,000 Mcf, whichever is greater, the charge for such excess take per Mcf shall be the commodity charge of the rate schedule increased by $\frac{1}{30}$ of the demand charge under the rate schedule; for excess takes above the stated demand by more than 2 percent but not more than 3 percent, or 1,000 Mcf, whichever is greater, a penalty charge of $2.00 per Mcf shall apply in addition to the commodity charge under the rate schedule; and for takes in excess of 3 percent of the stated demand or 1,000 Mcf, whichever is greater, a penalty charge of $5.00 per Mcf of excess shall apply in addition to the commodity charge under the rate schedule.

(7) It is necessary and desirable in the public interest that Mississippi be required to file applications for certificates of public convenience and necessity for authority to continue to serve such direct sales customers as it was not serving on the effective date of its "Grandfather" certificate.

(8) It is necessary and desirable in the public interest that Mississippi be required to file an application for a certificate of public convenience and necessity for authority to continue the operation of all facilities comprising its system for which it has not heretofore made application and received certificate authority to construct and operate.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission:

(A) Mississippi be, and it is hereby directed, to increase the stated demands of its present utility customers as follows, with the stated demands shown under the heading "New Stated Demands" to be effective upon the date this order becomes the final order of the Commission, and those shown under the heading "12-1-61 Stated Demands (Mcf)" to be effective December 1, 1961:

Customer	Present stated demands (Mcf)	New stated demands (Mcf)	12-1-61 stated demands (Mcf)
Arkansas Louisiana Gas Company	12,900	13,792	14,684
City of Altheimer	400	428	455
City of Augusta	858	917	977
City of Chester	641	685	730
City of Hazen	456	488	519
Fort Smith Gas Corporation	2,700	2,887	3,074
Illinois Power	56,323	60,218	64,114
Laclede	330,000	352,823	375,647
MidSouth	22,790	24,366	25,942
Missouri Natural Gas Company	24,000	25,660	27,320
Public Utilities Company (Crossett, Ark.)	1,900	2,031	2,163
St. Charles	2,360	2,523	2,686
Town of Des Arc	415	444	472
Union Electric Company	10,000	10,692	11,383
Village of Dupo	675	722	768
Natural Gas Improvement District No. 2 of Ashley County, Arkansas	374	400	426
Total	466,792	499,076	531,360

(B) Mississippi be, and it is hereby directed, to file, in a form acceptable to the Commission, the changes in or additions to its FPC Gas Tariff Original Volume No. 1 set forth in paragraph (6) above.

(C) Mississippi be, and it is hereby directed, to file an application or applications for certificates of public convenience and necessity for authority to continue to serve such direct sales customers as it was not serving on the effective date of its "Grandfather" certificate.

(D) Mississippi be, and it is hereby directed, to file an application or applications for certificates of public convenience and necessity for authority to continue the operation of all facilities comprising its system for which it has not heretofore made application and received certificate authority to construct and operate.

(E) The filings to be made by Mississippi pursuant to paragraphs (A), (B) and (C) above shall be made within 60 days from the date this order becomes the final act of the Commission.

FRANCIS L. HALL,
Presiding Examiner.

736-330—64——50

SUPPLEMENTAL DECISION

UPON A COMPLAINT AND APPLICATIONS FOR ORDERS DIRECTING INCREASES IN STATED DEMANDS

(Issued December 1, 1961)

HALL, *Presiding Examiner:* This case is before the Examiner for a second time primarily because, after the close of the initial hearing, the two largest utility customers of Mississippi River Fuel Corporation (Mississippi), namely, Laclede Gas Company (Laclede) and Illinois Power Company (Illinois Power), which are here continuing, along with other distributors, their prolonged efforts to obtain additional natural gas from Mississippi, partially relieved the pent-up demand for natural gas in their service areas by contracting to purchase 50,000 Mcf per day from a new pipeline that Mississippi caused to be constructed in the name of a subsidiary, Mississippi River Transmission Corporation (Mississippi Transmission), rather than as an integral part of Mississippi's system.

The Laclede and Illinois Power contracts executed after the close of the initial hearing and providing for the purchase of part of their natural gas needs from Mississippi Transmission (at 48.7 cents per Mcf as contrasted with Mississippi's 31.7 cent rate), were entered into in 1960. These contracts were executed after Mississippi had failed and refused for several years to expand its system, although it was clear that large additional supplies of gas were critically needed by Laclede, Illinois Power and other utility customers. This purposeful avoidance of needed expansion to keep pace with growth was the lever employed by Mississippi to force its utility customers in the St. Louis area, namely, Laclede, Illinois Power and St. Charles Gas Corporation (St. Charles), to pay substantially higher rates to Mississippi Transmission than could have been obtained by Mississippi following its past practice, as well as the ordinarily accepted practice in the industry, of enlarging facilities to meet increasing demands.

This case confronts the Commission with a natural gas company's disregard of its obligations to its utility customers, in an effort to preserve the profitability of its industrial sales, which denial of the relief sought herein by the utility customers would reward. The efforts of Mississippi in this proceeding to become locked in, and to cling to, the past with its unrestrained opportunity for high profits clearly does not harmonize with the Commission's task of facing the future and, with the aid of the Natural Gas Act (Act), to restrain the power of the strong over the weak. Performance of this task in this proceeding will mark a turn in the road for Mississippi.

As counsel for Laclede point out, "Mississippi conceives of the transportation capacity of its pipe line as principally a private matter with only grudging acceptance of the fact that, since the passage of the * * * Act, such transportation capacity has become affected with a public interest." In enacting the statute Congress clearly embarked upon a program of regulation through Commission control of a natural gas company's operations. Therefore, as the Examiner stated in his prior decision, "Mississippi's plea for self-regulation as to all aspects of its industrial business is * * * wholly untenable." In this area of the natural gas business the essential role of the Commission is to assure adequate service to the public at reasonable rates, not regulate the general public into using high cost gas for the sole purpose of protecting Mississippi's higher profits from the sale of industrial gas.

Contrary to the contentions of Mississippi and its industrial customers, this is not a case in which utility customers seek to take gas under Section 7(a) of the Act from direct industrial customers. Rather it is a situation in which

utility customers are asking that the pipeline's overall capacity be allocated in a manner consistent with the intent of the Act and most nearly designed to serve the public interest.

Following the initial hearing the Examiner, after an exhaustive study of the record and the briefs, issued his decision on September 13, 1960, disposing of the issues by granting the relief sought by Mississippi's utility customers to the extent possible to do so. That decision is still pending before the Commission and will be considered along with this Supplemental Decision dealing with the extent, if any, the evidence in the reopened record indicates a need for modification of the Examiner's decision issued September 13, 1960.

Mississippi's utility customers involved in this proceeding are in general agreement with the conclusion of Commission Staff counsel, as set forth in his brief in the reopened phase of this proceeding, "that the evidence introduced at the reopened hearings bore out the opinion the staff had following the issuance of the decision of the Presiding Examiner herein—at which time the staff determined not to file exceptions thereto—namely, that the Examiner's decision should be affirmed by the Commission." On the other hand, the briefs filed by Mississippi and its industrial customer-interveners set forth in large part a restatement of exceptions which they filed to the Examiner's decision.

In cases of this type the Commission must tailor its actions with the objective of realizing a sequence of successive expansions on the part of a pipeline company in which all customers pay their proportionate share of the cost and obtain their proper share of the gas supply made available. In contrast to Mississippi's failure to perform its public utility duty, other pipelines forging ahead in the competitive fuel business, such as Northern Natural Gas Company, for example, annually or periodically enlarge the total of their businesses so that all can enjoy the most flourishing growth possible—a growth so essential to the promotion of area and national interests. They recognize that economic progress is not made by standpatters; that a growing population, expanding economic activity, a rising standard of living, and greater mechanization have supported, and for the foreseeable future will continue to support, a growth in natural gas use; and that a key ingredient in any formula to spur and keep pace with economic growth and to meet commitments is their willingness to expand and move on to new sales opportunities. They also recognize that no one has a vested right to protection against the effect of price changes and that unless they are prepared to take risks and expand that economic growth in their service areas will be stifled and that they will find themselves pushed aside as more venturesome competitors take their place, just as others have been and are now actively investigating the opportunities for marketing natural gas in Mississippi's service area. In short, in the business life of other pipelines, and in business generally, the goal of growth is taken as a matter of course.

Any contrast of the progress and commendable outlook of either pipelines with the condition which Mississippi, for the sake of service-destroying maximum profits from industrial sales, created in its service area, particularly in the St. Louis area, will serve to emphasize the untenableness of Mississippi's position in this proceeding and the injustice it has inflicted upon those in its service area.

The following testimony of a Vice President of Illinois Power at the initial hearing, concerning what took place at a conference held in 1958 between representatives of Illinois Power, Laclede and the Chief Executive Officer of Mississippi, brings Mississippi's attitude in this proceeding into clear focus:

> * * * [The Chief Executive Officer] told me * * * that because of their rate and regulatory situation they had no intention of expanding the existing Mississippi * * * system.

> The officials of Laclede present at the meeting also stated that they would prefer the rolled-in supply. And [the Chief Executive Officer] on several occasions during the meeting reiterated that his company would give no consideration to supplying gas on this rolled-in rate basis,[1] and that it was—and I use his words—"The new subsidiary or nothing."

Mississippi, by standing its ground until 1960—during a time of critically short gas supply in its service area and skyrocketing producer prices—finally forced its hard-pressed utility customers in the St. Louis area to agree to bear the full cost of Mississippi Transmission's expensive gas supply. Mississippi progressed further towards its goal of "The new subsidiary or nothing" when construction and operation of the Mississippi Transmission system was authorized by the Commission on November 20, 1960, as amended on December 10, 1960, and advanced still further when its application, filed January 10, 1961, to reopen the record was granted over the vigorous protests of its utility customers, particularly Laclede and Illinois Power which had already contracted to purchase 50,000 Mcf of Mississippi Transmission's high cost gas. The Commission reopened the record because, in its opinion, "the changed circumstances which have occurred since the Examiner considered this matter and the issues involved should be decided upon as complete a record as possible" (*infra*, p. 768). However, that Commission action had the effect, insofar as Mississippi and its utility customers were concerned, of (1) foreclosing the possibility of immediate relief from Mississippi to its still hard-pressed utility customers—recommended by the Examiner in his decision issued September 13, 1960; (2) continuing the profitability of Mississippi's industrial sales; (3) causing Laclede and Illinois Power to again turn to Mississippi Transmission to increase their combined purchases from the latter from the initial 50,000 Mcf to 75,000 Mcf; (4) causing St. Charles to continue paying penalty payments to Mississippi for overrun gas and to contract for 1,000 Mcf of Mississippi Transmission's high cost gas; and (5) causing the other utility customers, whose locations prohibit them from purchasing gas directly from Mississippi Transmission, to also continue taking penalty gas from Mississippi and restrict service.

Mississippi having set out to attain its goal of "The new subsidiary or nothing," and having succeeded in creating its subsidiary with a separate system capable of providing gas either directly or, indirectly by displacement, to the industrial customers as well as the utility customers of Mississippi, this proceeding has now reached the point at which it is to be determined whether Mississippi's utility customers are to get "nothing" or "something" further from Mississippi. To put it another way, the outcome of this case will determine whether Mississippi is to be left in an "I told you so" position insofar as its utility customers are concerned.

The Examiner, in his decision issued September 13, 1960, determined that Mississippi has 64,568 Mcf of unallocated system capacity that it uses in serving its interruptible industrial loads, such service being provided under contracts with six-month termination clauses and subject to a prior claim to such gas by

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[1] The "rolled-in" rate method is explained in *Battle Creek Gas Co.* v. *F.P.C., et al.*, 281 F. 2d 42, 46, where Mr. Justice Reed, speaking for the Court, points out that under this method "the cost of the various assets of the system are collected or 'rolled in' to arrive at the cost of the entire system which is then pro-rated among all of the customers"; that "Use of the rolled-in method thus serves the interest of equal treatment for customers receiving equal service"; and that "the Commission has repeatedly stated a general preference for it whenever it may equitably be used."

Mississippi's utility customers. Notwithstanding the interruptible character of the industrial load, Mississippi's peak day service to industrial customers, as pointed out by counsel for Mississippi, "has been within a constant range of about 60,000 to 70,000 Mcf for at least 13 consecutive heating seasons * * *." This industrial service is provided in substantial part through capacity constructed without certificate authority and therefore in violation of the Act (*infra*, p. 760).

The Examiner found as a matter of law that the entire capacity of Mississippi's system must be dedicated on a two-step pro-rata basis (based on then-existing stated demands of all resale customers of Mississippi) to Mississippi's utility customers, except for minor amounts used in pilot lights, and if it is necessary to meet the needs of Mississippi's utility customers, Mississippi must curtail its industrial load. As stated in the pending decision, the

> * * * Examiner's order herein does not impair Mississippi's ability to render "adequate service" to industrial customers within the meaning of the Act, nor does it compel Mississippi to enlarge its existing facilities. Mississippi will be free to enlarge its facilities if it desires to furnish either firm service, or interruptible service in excess of present contract quantities, to its industrial customers, assuming the industrial customers are willing to continue to purchase gas on the terms offered by Mississippi. * * *

Mississippi sells natural gas to two types of customers: (1) utility customers—at the reasonable rate of 31.7 cents per Mcf determined by the Commission, and (2) industrial customers—at the much more profitable negotiated rates ranging from 32 to 50 cents per Mcf, these being rates at which Mississippi sold approximately 40 percent of its total annual capacity in 1960 to its industrial customers.

Although each of Mississippi's contracts with its industrial customers provides for interrupting service to such customers, Mississippi nevertheless contends that some of the industrials are firm customers, they being referred to in this proceeding as "firm-interruptible" customers.[2] As Mississippi's witness explained:

> Q. Well, now, do you consider all your firm industrial customers to be "firm-interruptible"?
>
> A. When it is necessary to interrupt them, yes, We don't plan it that way. * * * We don't want to curtail them. We oppose the 7(a)'s because it creates a situation that leads to that curtailment. If we have to curtail them to meet the utility load we do.

Not only does Mississippi have what it considers to be "firm-interruptible" and "true" interruptible direct sales, but it has in addition still higher priority interruptible direct sales made to customers willing to pay 50 cents per Mcf for gas so

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[2] The Examiner has pointed out in his decision issued September 13, 1960 that—

> On any day that Mississippi is unable to deliver to one of its "firm-interruptible" customers all the gas it could have used on that day—regardless of its maximum contract volume—Mississippi considers that that customer has been "curtailed." As a witness for Mississippi put it, "Curtailment to us means anything that is cut by our request below the volume that they would actually need on the day that the curtailment takes place." He furher explained: "Naturally when we start curtailing we curtail the lowest price gas first and work our way up to the highest price, and vice versa when we are putting the gas back on." Operating on this basis Mississippi considers that during the 1958–59 heating season it curtailed some of its "firm-interruptible" customers on five days, yet on those same days it was delivering over the contract maximum volumes to other of such customers and even selling some gas to what it regards as "true" interruptible customers.

that, should any curtailment occur, they will be the last curtailed.[3] Mississippi's witness testified:

> The WITNESS: The 50 cents is interruptible gas.
>
> PRESIDING EXAMINER: Yes. But it is, as * * * you agreed, at the top of the totem pole, so to speak.
>
> The WITNESS: Yes, that is right.

Mississippi's direct industrial sales are returning some $6,465,000 a year in excess of Mississippi's own allocated cost of service to those sales—which includes a return on its investment to Mississippi of 6½ percent.[4] A rate witness for Laclede measured the cost to Mississippi's system if Mississippi itself incurred the cost of the additional gas supplies from Mississippi Transmission on behalf of all of its customers. As he testified, if Mississippi itself incurred the cost of the additional 75,000 Mcf per day (which Laclede and Illinois Power have now contracted to purchase from Mississippi Transmission), Mississippi revenues would only be some $700,000 annually less than the combined revenues of Mississippi and Mississippi Transmission. If the volume of Mississippi Transmission gas to be rolled-in were to increase to 100,000 Mcf per day, the loss in Mississippi revenues would amount to some $800,000 annually. An increase in rolled-in volume to 125,000 Mcf per day would represent a total reduction in revenue of some $900,000 annually. In short, a purchase by Mississippi of Mississippi Transmission gas would at worst result in a reduction of Mississippi's $6,465,000 "excess" profit by some $700,000–$900,000 per year.[5]

Mississippi has some 48 industrial customers of which 13 intervened in this proceeding. These industrials recognize that Mississippi has been exacting high rates for its service. As stated by counsel for one industrial-intervener, independent of the evidence "Owens-Illinois is aware of the fact that Mississippi's direct industrial service to Owens-Illinois is more than paying its own way, and that Mississippi is deriving at least a handsome profit on such gas sales." Like other industrial-interveners in this proceeding, this intervener complains that Mississippi's utility customers pay no more than their proportionate share of Mississippi's jurisdictional cost of service as determined by the Commission, whereas Mississippi's direct industrial customers do not have such protection. This complaint of lack of Commission jurisdiction over industrial rates is one that should be addressed to Congress, not to the Commission. Commission jurisdiction

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[3] Counsel for Mississippi at page 51 of their brief argue that Mississippi's direct sale customer contracts "clearly are not 'interruptible' contracts as the Examiner supposed." They correctly state the fact at page 46 when they point out that the contracts "provide that 'Seller will give priority' to the demands of 'public utility distribution companies', and that deliveries to the direct customer 'will be curtailed from time to time and on occasion may be completely interrupted.'" In law and in fact Mississippi's contracts with its direct industrial customers are truly interruptible contracts.

[4] During the year ended December 31, 1960, Mississippi's revenues from nonjurisdictional sales were $23,640,000, as compared to $17,175,000 which Mississippi has allocated as cost of service for such sales in the same period. The dollars of allocated costs include very substantial amounts paid to United Gas Pipe Line Company subject to refund. To the extent of any such refunds which Mississippi may receive from United, and not pass out to its direct industrial customers, the $6,465,000 per year of earnings in excess of a 6½ percent rate of return is understated. It is also clear that it may also be understated for a number of other reasons mentioned by Laclede's rate witness.

[5] Laclede's witness explained that "It is apparent * * * that any additional sales which Mississippi makes to utility customers on a basis wherein the return is regulated, and any reduction in sales which Mississippi makes directly to industrial customers on a basis wherein the return is not regulated are going to produce some dilution of Mississippi's over-all return and earnings. This does not mean that the additional sales to the utility customers would be made at less than properly allocated costs. It merely means that they would be made with less margin of profit than the present margins of profit on Mississippi River Fuel's system from its direct industrial customers."

over industrial rates could long ago have nullified Mississippi's excess profit motive which has caused such great distress in its service area.

Counsel for Mississippi also assert irrelevently that Laclede, not Mississippi, "is the giant in these proceedings." They point out in this connection that "Mississippi's net investment in gas transmission properties is approximately $80,000,000 compared to Laclede's net investment in utility plant of approximately $120,000,000." However, the size of Laclede's utility plant only emphasizes why Laclede has so desperately sought additional gas from Mississippi to feed its plant and maintain its financial integrity. The absence of adequate supplies of pipeline gas would place Laclede in the position of an automobile owner without sufficient gasoline to propel his automobile. From the public standpoint lack of adequate gas supply from Mississippi adversely affects the thousands of consumers supplied by Laclede's distribution system. Moreover, the only reason that Mississippi's investment in its gas transmission properties is no more than $80,000,000 is because, contrary to the wishes of its utility customers, it has failed to expand its system to meet needs in its service area.

As already stated, Mississippi's opposition to the requests of its utility customers herein for increases in their stated demands (stated demands are equivalent to contract demands), through allocation of the 64,568 Mcf of unallocated capacity hereinabove referred to (*supra*, pp. 750–751), is motivated by its desire to perpetuate the present profitability of its industrial sales. On the other hand, the utility customers seek their share of Mississippi's unallocated capacity along with appropriate changes in Mississipi's FPC tariff which now provides for only one service under one rate schedule to the utility customers (except for one standby service not important here).

At the reopened hearing Mississippi's President testified that Mississippi—

> * * * is not a company that is going to forever stand up and say it will never do anything to benefit anyone if it costs it some money, but I think most of the people who run Mississippi, and I'm speaking of the Board of Directors, do feel that this type of thing results in too severe a penalty and the question comes down, is it our obligation to do that sort of thing.
>
> I mean, how far does that obligation extend?

How far does Mississippi's obligation to its utility customers extend? The answer to this question is to be provided in the disposition of this case. The answer should have been clear to Mississippi for some time in view of the provisions of the Act; its service obligations to its utility customers; its interruptible contracts with its industrial customers; the fact that as far back as 1946 (5 FPC 206, 210) the Commission made it clear that all of Mississippi's system capacity would eventually be devoted to utility sales unless Mississippi increased the capacity of its system from time to time; and the fact that Mississippi's attempt here to avoid further erosion of its earnings from its industrial sales is the same position it took unsuccessfully in *Mississippi River Fuel Corp.* v. *F.P.C.*, 252 F. 2d 619, 624, in opposing the higher single rate there involved because it was injurious to its industrial sales. In that case the court, in rejecting the reasons for Mississippi's opposition, stated:

> Mississippi makes two principal claims of damage to it. It claims that the single rate hurts it more than it hurts other purchasers from United since a larger proportion of its purchases were under the older, lower contract rates whereas the greater part of the others' purchasers were under newer, higher contract rates. Again, the commodity price in the single rate is twice that in the old contract rate, and Mississippi claims

> that, because rates to *interruptible industrial consumers* are pegged largely on the commodity rate, the double rate is particularly injurious to that phase of Mississippi's operations. Sales direct to industry are not regulated by the Commission, but it can influence these rates by its allocation of costs to industrial business as part of its determination of rates over which it has jurisdiction. A low commodity rate would enable Mississippi to meet competition from other fuels without jeopardizing its profits from its jurisdictional sales. These seem to be the principal reasons for Mississippi's opposition to single rate. *While they are potent from the standpoint of that company, they do not avail too much from the standpoint of general regulation and the public interest.* [Emphasis supplied.]

Also pertinent is the statement of the Supreme Court in *Dayton-Goose Creek Railroad Co.* v. *United States*, 263 U.S. 456, 461:

> By investment in a business dedicated to the public service the owner must recognize that, as compared with investment in private business, he cannot expect either high or speculative dividends but that this obligation limits him to only fair or reasonable profit.

In this proceeding, it is the public interest, not Mississippi's private interest, that must prevail. If the public interest does not prevail Mississippi will have succeeded in ridding itself of its service obligations to its utility customers and will be enabled to maintain its present profit margins from industrial sales at the expense of the customers of its utility customers, thereby effecting the destruction, insofar as Mississippi is concerned, of the "primary aim" of the Act which is "to protect consumers against exploitation at the hands of natural gas companies" (*Federal Power Commission* v. *Hope Natural Gas Co.*, 320 U.S. 591, 610).

Counsel for Mississippi assert that the testimony of the President of Mississippi at the reopened hearing "displayed no more or less than a proper interest in his stockholders." The outlook of the Commission and its powers, however, are greater than the interest of Mississippi's stockholders. That outlook is as comprehensive as the total public interest. The idea of Mississippi to maintain the present level of its earnings from its industrial sales is attractive to it, but that idea has to be tested in relation to (1) the interest of all natural gas users in Mississippi's service area; (2) its effect upon utility customers; and (3) the factor of growth as a pattern for expansion in volume and extension of service in Mississippi's service area. When so tested the position of Mississippi is found to be totally lacking in merit.

If a natural gas company in a changing service area is not to go to waste, insofar as providing needed additional service is concerned, and if the public interest is not to be jeopardized, it is necessary from a regulatory standpoint to take such action as will cause the company to perform its duty and to adjust its profits to existing circumstances and regulatory requirements. Reduced profits from the industrial sales here under consideration results from shifting and growing requirements in Mississippi's market, and from higher cost gas supplies and facilities. This, from Mississippi's point of view, may be regrettable. It is nevertheless unavoidable and is one of the prices Mississippi must pay for progress and for being a natural gas company (Cf. *United States* v. *Appalachian Electric Power Co.*, 311 U.S. 377, 427–428).

As already indicated, from 1957 until after the close of the initial hearing both Laclede and Illinois Power opposed Mississippi's plan to provide their

additional natural gas requirements through Mississippi Transmission's system. But Mississippi, by adhering to its unyielding position that it was "The new subsidiary or nothing", finally succeeded in 1960 with a revised subsidiary plan which, while more favorable to Laclede and Illinois Power than Mississippi's original proposal, was not preferred by these distributors and constitutes only a partial and unsatisfactory solution to their gas supply problem.

In causing Mississippi Transmission's system to be constructed and operated as a separate system, Mississippi abandoned its past practice of expanding and extending its own system and rolling in the costs of new gas and additional capacity with other system-wide costs in arriving at rates. Under that practice the costs of expansions were shared proportionately by all of Mississippi's customers. Abandonment of this practice was designed by Mississippi to prevent any further dilution of its highly profitable earnings from its industrial sales.[6] This was accomplished by saddling the utility customers in the St. Louis area with the entire burden of Mississippi Transmission's higher cost gas supply. That is to say, by use of the subsidiary approach, costs of constructing Mississippi Transmission's pipeline and its substantially higher cost gas supply were passed on to Mississippi's utility customers because they are the only customers of Mississippi Transmission. The industrial customers, by continuing to purchase gas directly from Mississippi, would not share in the cost of Mississippi

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[6] The basic reason for the existence of Mississippi Transmission is as explained by the President of Mississippi at the reopened hearing:

PRESIDING EXAMINER: In short, what you are saying is that Mississippi * * * Transmission * * * was organized for the purpose of protecting the profitability of Mississippi River Fuel's earnings to the extent that it is possible to do so?

The WITNESS: That, I would say was the principal reason, yes.

* * * * * * *

PRESIDING EXAMINER: I believe that Mr. Kramer has testified that the approximate cost of Mississippi * * * Transmission Corporation's 93 mile transmission line to date is $6 million. Now, it is a fact * * * that Mississippi * * * in the past has constructed improvements and additions and expansions to its system that cost in excess of that amount?

The WITNESS: Oh, yes.

* * * * * * *

PRESIDING EXAMINER: Now, the difference in the tariff rate [of Mississippi and Mississippi Transmission] is accounted for by the fact that Mississippi * * * Transmission * * * facilities and natural gas cost are higher than those of Mississippi * * * is that not so?

The WITNESS: Primarily the gas costs. Plus the fact that [Mississippi] Transmission * * * does not have a large volume of industrial sales which contribute very substantially, of course, to lowering the price to utilities under the cost allocation methods.

* * * * * * *

PRESIDING EXAMINER: To your knowledge has Mississippi * * * ever proposed to supply the needs or any part of the needs of its industrial customers through a new and separate subsidiary such as Mississippi * * * Transmission * * *?

The WITNESS: No, not to my knowledge.

* * * * * * *

PRESIDING EXAMINER: Well, if Mississippi * * * had desired to do so it could have constructed the line now owned by its subsidiary * * *?

The WITNESS: Yes.

PRESIDING EXAMINER: Rolled that cost, which is now incurred by the subsidiary, into its costs, sold the gas to the industrials with Mississippi in that process recovering a great deal higher profit from those [industrial] sales than it reaped from the sales to the utilities; now, isn't that so?

The WITNESS: It could have, and does make more profit on its non-regulated business than it does on its regulated business, but if it should do what you just suggested it would make less profit and that would be a continuing thing as the utility load grew. I mean, it is a constant attrition of those earnings.

Transmission's system, nor would Mississippi's earnings from its industrial sales be eroded.

Laclede's urgent need for additional gas at the time of the acceptance of the revised subsidiary plan in 1960 is set forth in the following testimony of its President at the reopened hearing:

> Q. The record in this proceeding contains testimony by you that Laclede was offered an additional supply of gas by a subsidiary of Mississippi and that you turned it down principally because of the price. Why then, since the Examiner's decision in this case, have you accepted additional deliveries of gas from that same subsidiary?
>
> A. We have been taking care of our very limited load growth for over five years from our storage without any addition to our pipeline supply. However, the time had come when storage could not continue to provide for our growth and we were desperately in need of additional pipeline flow. Further, in several respects the proposal which we did accept was much different from the original proposal.
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> * * * * * * *
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> PRESIDING EXAMINER: Just how desperate were you for gas? * * *
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> The WITNESS: In 1955 Laclede got an increase * * * from 300,000 to 330,000. I might point out that I came to Laclede as its president on May 1, 1956, and I saw from almost the very day I went to work that we were in need of pipeline gas to supplement the development of the storage. I started work on it then, and it was five years later to the very day, on May 1, 1961, that we opened the valve and turned in the first additional gas that we had gotten from anywhere and that was this [Mississippi] Transmission gas.
>
> * * * * * * *
>
> I can truthfully say that I have spent probably a third of my working time on that one problem during those five years.
>
> PRESIDING EXAMINER: Was the growth of your company in any way hampered as a result of the lack of pipeline supply of gas?
>
> The WITNESS: Yes, sir.
>
> PRESIDING EXAMINER: Would your company be any larger today in terms of service if you had progressively gotten what you considered to be your need?
>
> The WITNESS: Our company would be larger in terms of the number of heating customers, it would be larger in terms of gross revenues, annual send-out, I hope in net income. We would be larger in every respect if we had an unlimited supply of gas.

In connection with this testimony it should be observed that in contrast to the initial 50,000 Mcf per day Mississippi Transmission contracted to sell to Laclede (42,500 Mcf) and to Illinois Power (7,500 Mcf) beginning in May 1961, Laclede, in 1958, had advised Mississippi that it would purchase an additional 100,000 Mcf at any time prior to the fall of 1960, and Illinois Power, in 1957, had advised Mississippi that it was prepared to purchase an additional 45,000 Mcf "regardless of whether or not we find storage." During the last ten years, Mississippi, Laclede's sole supplier of natural gas up until 1961, has made available to Laclede little more than 60,000 Mcf of additional gas per day.

Mississippi Transmission is now authorized to deliver, effective December 1, 1961, 63,750 Mcf of natural gas per day to Laclede and 11,250 Mcf per day to Illinois Power, which gas Laclede and Illinois Power are obligated to take (or

pay for) on the basis of 75 percent load factor at a price of 46.3 cents per Mcf.[7] This 46.3 cent price is to be contrasted with the substantially lower price of 31.7 cents per Mcf at which Laclede and Illinois Power buy gas from Mississippi at 60 percent load factor.

The Examiner's decision issued September 13, 1960, allocates the 64,568 Mcf of capacity now utilized by Mississippi in serving its industrial load to Mississippi's utility customers on a pro-rata basis, such method resulting in 45,647 Mcf of the total being allocated to Laclede commencing on December 1, 1961. The following testimony of Laclede's President contrasts the price impact of this volume of gas as between Mississippi and Mississippi Transmission:

> Q. If that amount [45,647 Mcf] of additional gas is not made available from Mississippi * * * what will you do?
>
> A. We will have to get an equivalent volume of gas somewhere else. As Mr. Liberman's testimony shows, we need this gas and after that we still need more gas.
>
> Q. Assuming that the 45,647 Mcf had to be purchased from Mississippi * * * Transmission * * * at that company's presently filed tariffs, how much more would you have to pay for the gas than you will if the Examiner's decision is upheld and you are permitted to purchase the same volume of gas at Mississippi River Fuel's presently filed tariffs?
>
> A. At the currently effective tariffs the volume of gas involved, 45,647 Mcf of demand, would cost almost $2,500,000 more per year purchased from Mississippi * * * Transmission * * * rather than from Mississippi * * *. This is about 70 percent more. It is true, however, that Mississippi * * * rates will probably increase June 15, 1961, and the Transmission Corporation will probably decrease in December 1961, when that system begins to transport larger volumes of gas. Taking these two factors into account, the purchase of the 45,647 Mcf volume allocated to Laclede by the Presiding Examiner would cost about $3,800,000 a year purchased from Mississippi * * *, but the same volume would cost $5,800,000 a year if purchased from [Mississippi] Transmission * * *. This is an annual difference of about $2,000,000 and means that gas purchased from Transmission would cost Laclede approximately 55 percent more than it would purchased from Mississippi * * *.

Counsel for Mississippi claim that "Laclede in this case unlawfully sseks relative cheap volumes of gas, heretofore served by Mississippi to longtime industrial markets in St. Louis, so that Laclede profits may be further enhanced and its dividends to stockholders increased." This claim will not bear analysis. While Laclede naturally expects all of its sales to be profitable, regardless of the source of its gas supply, it will be the ultimate consumer, not Laclede, who will be the real beneficiary of the savings involved in the purchase of lower

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[7] The average cost to Laclede and Illinois Power of purchasing the initial 50,000 Mcf from Mississippi Transmission was 48.7 cents per Mcf as compared with the average cost of 46.3 cents per Mcf for the purchase of 75,000 Mcf as of December 1, 1961. As the President of Mississippi Transmission explained, the lower average cost of 46.3 cents per Mcf for the 75,000 Mcf results from the fact that "when you increase the volumes and as the operating costs do not increase this decreases the average cost of gas to Laclede and Illinois Power." Assuming no change in the cost of purchasing gas from Trunkline, the average cost of 100,000 Mcf per day would be 44.8 cents per Mcf at 75 percent load factor. Making the same assumption, the average cost of 140,000 Mcf would be 43.6 cents per Mcf. This would also be the average cost of 200,000 Mcf because of the added cost to Mississippi Transmission of compression needed to transport 200,000 Mcf.

cost gas from Mississippi.[8] Counsel for Mississippi make this fact clear on the preceding page of their reply brief when they point out that "Laclede on May 12, 1961, filed with the Missouri Commission a revision of its tariffs to increase its rates to recover increased gas costs occasioned by the purchase of gas from [Mississippi] Transmission." Had Laclede obtained the same volume of gas from Mississippi that it purchases from Mississippi Transmission, there would be no necessity for Laclede to recover the higher cost of Mississippi Transmission's gas from ultimate consumers through higher retail rates. Also not to be ignored is the fact that Laclede's efforts to improve its business are directed at fulfilling its public utility responsibility and advancing economic growth; that Laclede's performance of its expected duty can provide no comfort to Mississippi for its failure to live up to its public utility obligations; and that a cardinal principle in the industry should be that every utility provide new increments of gas at the lowest possible cost. As the court said in *El Paso Natural Gas Co.* v. *F.P.C.*, 281 F. 2d 567, 573, "It is the obligation of all regulated public utilities to operate with all reasonable economies."

The evidence makes it apparent that notwithstanding the fact that the public interest demanded otherwise, Mississippi, solely because of its high profit motive, elected to stand still until 1960 when it finally succeeded with respect to the construction of Mississippi Transmission's system in lieu of a further enlargement of its own system. The reason for this standstill must be removed if Mississippi is to be moved to serve the public interest. Failure to remove it might encourage other natural gas companies to also ignore the public interest by becoming too choosey about what service they will render and waiting for something at least as good as present profits to come along. Important to this consideration is the following statement of the Supreme Court in *United Gas Co.* v. *Railroad Commission*, 278 U.S. 300, 309, relating to a request made to a State Commission for higher rates or, in the alternative, withdrawal from service which the company had undertaken:

> The primary duty of a public utility is to serve on reasonable terms all those who desire the service it renders. This duty does not permit it to pick and choose and to serve only those portions of the territory which it finds most profitable, leaving the remainder to get along without the service which it alone is in a position to give. * * *

And in *Pennsylvania Water & Power Co.* v. *Consolidated Gas Electric Light and Power Company of Baltimore*, 184 F. 2d 552, 567, the court said that—

> One of the most important duties of a public utility, inherent in its franchise to serve the public, is the duty to take the initiative in * * * rendering adequate service, taking into account changing conditions; and the utility is not relieved from this duty because its activities are subject to governmental regulation, for a regulatory commission is not clothed with the responsibility or qualified to manage the utility's business. * * *

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[8] At one point in his testimony at the reopened hearing the President of Mississippi testified:

PRESIDING EXAMINER: * * * The person that really benefits is the ultimate consumer, isn't it? Isn't that the way it works?

The WITNESS: Yes, that is true, and I am not a Simon Legree, understand, but I have never been able to quite get through my head why it is that a customer who has been using oil or propane or whatever he uses to heat his house should be subsidized, so to speak, to too great an extent either by our industrial customers or by Mississippi stockholders. I mean, to me that is a little hard to fathom. * * *

In this testimony the President of Mississippi appears to overlook the fact that Laclede's need for additional pipeline gas does not flow solely from conversions from other fuels to natural gas, but also from increased needs of existing customers and from new housing and other developments.

It would have been far better if Mississippi had concentrated its energies over the past few years on increasing the supply of natural gas through a further enlargement of its system at reasonable rates rather than in devising plans to keep its present wealth from industrial sales and sidetracking the fruitful path of economic growth. Had it set the stage for further expansion by adopting a policy of equal treatment for all, it would have raised the horizons of individual and collective progress. It would have been much easier to have allowed everyone a larger slice out of a bigger cake than to attempt to maintain the division of a smaller cake.

Service Rendered by Mississippi to Its Industrial Customers

The interruptible character of Mississippi's service to its direct industrial customers has been commented upon hereinabove (*supra*, pp. 751–752). However, the following excerpts from the Examiner's decision issued September 13, 1960, will serve to provide a broader understanding of Mississippi's method of operation under its existing inequitable tariff provisions.

> The present provisions of Mississippi's FPC Gas Tariff enable Mississippi to make available to its industrial customers all gas not taken by the utilities. This means that Mississippi has been making available to its industrial customers that part of the 466,792 Mcf not at times being utilized by the utility customers, plus the difference between the present stated demands and the total capacity of the system. The industrial customers, therefore, take their total requirements up to the capacity of Mississippi's system to deliver. That is to say, except as they may, or some of them may, at times be limited in their takes by the capacity of Mississippi's system, the industrial customers take as much or as little gas as they need on any day, this being permitted by the lack of any contract minimum bill or overrun penalty. On the other hand, the utility customers not only pay a minimum bill but a substantial penalty for takes in excess of stated demand. The heavy overrun penalty applicable to utility customers and the failure of the tariff to make provision, as is the case with respect to other suppliers, for the utility customers to share in excess gas available on Mississippi's system, have the practical effect of assuring the industrial customers that there is available for their use at all times substantially all gas on Mississippi's system in excess of stated demands, as well as that part of the stated demands not taken by the utilities from time to time.
>
> * * * * * * *
>
> The instability of what Mississippi conceives to be requirements is further strikingly illustrated by its continually changing "requirements." As counsel for Laclede point out, Mississippi "has employed an 'allocation' system in apportioning firm industrial gas which has permitted an industrial customer to increase its entitlement during peak periods simply by using more gas during off-peak periods, thereby building up its quota or 'credit' in the preceding month * * *."

Mississippi's System Capacity and Unauthorized Construction of Facilities

Mississippi began operating its system in 1929 with a designed daily sales capacity of about 100,000 Mcf. By 1942 that capacity had increased to 135,000 Mcf. Mississippi's second line project, i.e., looping program involving an increase in sales capacity from 135,000 Mcf to 183,000 Mcf, was commenced pursuant to certificate authorization granted on August 28, 1946, with the Commission recognizing in its opinion (5 FPC 206, 210) that all of Mississippi's system capacity

would eventually be devoted to utility sales unless Mississippi continued to increase the capacity of its system from time to time. The Commission stated:

> * * * For the peak day of 1950, it appears that unless additional facilities are installed, almost 100 percent of the system sales capacity of 181,000 Mcf will be devoted to utility sales.
>
> Applicant estimates that with presently proposed facilities it will be necessary to curtail its firm industrial sales on system peak day for each of the calendar years 1946 to 1950, inclusive. * * * Applicant has indicated its intention to add facilities from time to time as warranted by the increases in demands. * * *

Authority to complete the looping program, giving a system daily design sales capacity of 266,000 Mcf, was granted by the Commission on December 8, 1947 (6 FPC 280). In connection therewith it was estimated that on the peak day in the years 1947 through 1951 Mississippi would have to curtail deliveries to its direct industrial customers in order to meet the demands of its resale customers.

The system design sales capacity was increased by successive steps from 266,000 Mcf in 1950 to 450,000 Mcf in 1952, exclusive of any gas that might become available from Waterloo storage (9 FPC 219; 9 FPC 1187; 11 FPC 760, 11 FPC 1219).

In 1952 (11 FPC 1219), and subsequently on June 3, 1953 (12 FPC 151), the Commission made the latest allocation it has made of Mississippi's capacity. The then claimed total delivery capacity of Mississippi's system was 450,000 Mcf, of which 415,000 Mcf, or 92 percent, was allocated to utility customers and 35,000 Mcf, or 8 percent was permitted to be used in connection with Mississippi's industrial sales. In that connection the Commission adopted an agreed-to schedule of stated demands allocating the 92 percent of Mississippi's capacity among its utility customers on the basis of a stipulation that the amounts stated would not affect rights under existing utility contracts.

While Mississippi and the other parties agreed to the allocation of 450,000 Mcf, represented by Mississippi to be the design sales capacity of its system, the record shows that in the summer of 1952 Mississippi, *without certificate authorization*, increased its system sales capacity by some 50,000 Mcf, or to 500,000 Mcf, by "pigging" a portion of one of its two transmission lines, adding some horsepower to raise the pressure on its two lines by 25 psi each, and by the installation of "cross-overs" between its two lines.

Today Mississippi claims that the designed daily sales capacity of its system is 524,000 Mcf, an increase of 74,000 Mcf over the 450,000 Mcf capacity alleged in 1952 and 1953. Except for (1) 10,000 Mcf additional capacity authorized by order issued August 2, 1957 (18 FPC 106), and (2) a claimed 7,000 Mcf additional capacity authorized by order of October 1958, or a total of 17,000 Mcf additional capacity, the claimed increase of 74,000 Mcf between the 450,000 Mcf and the alleged 524,000 Mcf design sales capacity as of today *was accomplished without Commission authorization.*

On the basis of the evidence the Examiner has determined that the sustained dependable delivery capacity of the system is not less than 534,000 Mcf—or 10,000 Mcf in excess of that now claimed by Mississippi, of which not less than 447,303 Mcf is deliverable in the St. Louis area. Mississippi's deliveries to its industrial customers, most of which are in the St. Louis area, has been within a constant range of about 60,000 to 70,000 Mcf for at least 13 consecutive heating seasons.

The facts make it clear that when Mississippi wanted to serve its very profitable industrial customers more gas than contemplated by the Commission's

orders, it disregarded those orders and the law and constructed unauthorized capacity. But when the utility customers desperately needed more gas to serve the general public at reasonable rates determined by the Commission, Mississippi stood still until 1960 when it got its own way with respect to the construction of Mississippi Transmission's system, and concentrated its efforts on fighting off the requests of its utility customers for increases in their stated demands.

Because of Mississippi's unauthorized construction, the Examiner's decision issued September 13, 1960, directs Mississippi "to file an application or applications for certificates of public convenience and necessity for authority to continue the operation of all facilities comprising its system for which it has not heretofore made application and received certificate authority to construct and operate." As the Examiner stated in his prior decision:

> All changes in capacity are required in good conscience and the law to be disclosed at the time they take place. Discovery of the existence of unauthorized capacity increases and their unauthorized employment by Mississippi should result in the taking of affirmative steps by the Commission to assure that the unauthorized and discriminatory conduct exercised in the past will not be continued or repeated in the future.

The importance of timely compliance with the Act and the Commission's rules and orders to the efficient exercise of the Commission's duties cannot be overemphasized. This is especially true with respect to system capacity which is the subject of these proceedings. Moreover, the deliberate acts of Mississippi in increasing the capacity of its system without Commission authorization are attended by no extenuating circumstances whatever. Had Mississippi proceeded on *bona fide* mistake of law, the Examiner would hesitate to recommend application of penalties. But here its offense is aggravated by its attempt to ignore certificates procedures in total disregard of the consequences attaching to its unlawful conduct. To allow such instances of willful failures to pass without the fullest penalties provided by the Act is to invite further inexcusable resistance to the requirements of the statute. Therefore, the Examiner's order directs that a copy of the record herein be transmitted to the Attorney General of the United States with a request that criminal proceedings be instituted, under the provisions of Sections 20 and 21 of the Act, against Mississippi and its officers and directors.

Reasons Why Laclede and Illinois Power Finally Agreed To Purchase Part of Their Additional Natural Gas Requirements From Mississippi Transmission

Laclede and Illinois Power, after the closing of the initial hearing, agreed to purchase natural gas from Mississippi Transmission because of their desperate need for additional pipeline gas and because of the more favorable terms of the proposal they accepted in 1960.

The Vice-President of Illinois Power testified that Illinois Power "generally concluded that the substantial differences in price and take and pay provisions and the potentiality of the St. Jacob storage field justified our signing the contract" with Mississippi Transmission. The President of Laclede testified:

> In the first place, the delivered cost of the gas is less than under the prior proposed arrangement. In the second place, the gas is being delivered to us in a small initial quantity with options in the agreement to increase the quantities at stated intervals, thus making it possible to absorb the gas into our system in a more orderly fashion. In the third place, the Mississippi River Transmission proposal provided for the utilization of the St. Jacob

Storage Field which is currently under development, and although Mississippi Transmission turned down the certificate granted, we still have hopes that the field will ultimately be fully developed under circumstances which will make the overall new project a great deal more attractive to us. In the fourth place, and not by any means the least of the considerations, is the fact that our new delivery point is in the extreme northwest end of our distribution system and very close to our own storage, which was not true of the original proposal; also the delivery pressures are high enough to permit injection of the gas into the St. Peter formation without compression.

All these considerations made it seem to us that this proposal was sufficiently attractive for us to accept it.

I would like to point out, however, that Mr. Liberman testified in detail the amount of gas which we are purchasing from Mississippi Transmission does not solve the problem of gas supply for the St. Louis area.

Negotiations Relating to Mississippi Transmission's Gas Supply and Construction of Its System

At the time Mississippi organized Mississippi Transmission in 1958 it was contemplated that the latter would obtain its gas supply from Texas Eastern Transmission Corporation near Oran, Missouri. However, negotiations carried on in 1960 led to an agreement between Mississippi Transmission and Trunkline Gas Company (Trunkline) dated April 26, 1960, and an agreement among Mississippi Transmission, Laclede and Illinois Power dated April 22, 1960. The Mississippi Transmission-Trunkline agreement provided for Mississippi Transmission's purchase from Trunkline of 50,000 Mcf per day initially, with options to increase the quantity to 75,000 Mcf on December 1, 1962, and 100,000 Mcf on December 1, 1964. The agreement with Laclede and Illinois Power provided for the sale of 85 percent of this gas to Laclede and 15 percent to Illinois Power.

Construction of Mississippi Transmission's 93-mile pipeline commenced on January 3, 1961. Deliveries of gas through the pipeline commenced to Laclede on May 1, 1961, and to Illinois Power on May 10, 1961.

Laclede and Illinois Power each have entered into a 20-year service agreement with Mississippi Transmission, dated March 29, 1961. Laclede's initial contract quantity was 42,500 Mcf per day, and Illinois Power's was 7,500 Mcf per day. The gas is sold to them on a 75 percent annual load factor basis, which is the same basis that Mississippi Transmission purchases the gas from Trunkline.

By an agreement between Trunkline and Mississippi Transmission dated February 24, 1961, Trunkline agreed to accelerate the dates on which increased quantities could be obtained by Mississippi Transmission under the options contained in the prior agreement. Under this agreement, an additional 25,000 Mcf per day is to be made available on December 1, 1961, and a further 25,000 Mcf per day could be made available on December 1, 1962.

On May 11, 1961, the Commission issued temporary authorization to Trunkline and Mississippi Transmission to commence the sale of the first additional 25,000 Mcf per day. Thus, commencing December 1, 1961, the total quantity available from Mississippi Transmission will be 75,000 Mcf per day, of which Laclede's portion is 63,750 Mcf and Illinois Power's is 11,250 Mcf. If the options for the next 25,000 Mcf are exercised, and assuming Trunkline can obtain adequate reserves for additional deliveries and Commission authorization is obtained, 100,000 Mcf per day would be available by December 1, 1962, of which Laclede would have 85,000 Mcf and Illinois Power 15,000 Mcf. Trunkline has expressed a willingness to further increase the available quantity to 150,000 Mcf,

but Laclede and Illinois Power are withholding any indication of their desire to purchase this additional gas until the outcome of the instant proceeding is known.

Mississippi Transmission Represents a Supply of Gas Which Can Be Made Available to All of Mississippi's Customers

Mississippi Transmission was organized by Mississippi and is the agent of the latter. Notwithstanding the attempt to create the appearance of two corporations functioning separately, the Commission must pierce the corporate veil and recognize that those carrying on negotiations in the name of Mississippi Transmission are in fact negotiating with Mississippi. As the Supreme Court of the United States so aptly said in the case of *Electric Bond and Share Co.* v. *Securities and Exchange Commission*, 303 U.S. 419, 440, "It is the substance of what they do, and not the form in which they clothe their transactions, which must afford the test." The Commission must recognize, as did the Supreme Court in *Southern Pacific Terminal Co.* v. *I.C.C.*, 219 U.S. 498, 523–524, that "it is with the system that the law must deal, not with its elements. Such elements may, indeed, be regarded from some standpoint as legal entities; may have, in a sense, separate corporate operation; but they are directed by the same paramount and combining power and made single by it." Under no circumstances can Mississippi relationship to Mississippi Transmission be regarded as a means of insulating Mississippi from its statutory responsibility to its utility customers.

The as-is capacity of Mississippi Transmission's system is in excess of 140,000 Mcf per day, of which Laclede and Illinois Power have contracted to purchase 75,000 Mcf. With compression of about 7,500 horsepower, estimated to cost $2,500,000, the capacity could be increased to 200,000 Mcf per day.

Mississippi Transmission's system crosses over the main line of Natural Gas Pipeline Company of America near Shattuc, Illinois. The Commission, by order issued September 26, 1961, in Docket No. CP61–339, authorized an interconnection between these two pipelines for the purpose of making deliveries of natural gas "to each other when such deliveries are desirable to insure continuity of service to their respective customers during periods of emergency." As the President of Mississippi Transmission testified, when his company got gas "from Natural Gas Pipeline Company of America, which is much closer to the St. Louis area, or if we develop some business in that immediate area, we may have much more delivery capacity than" 200,000 Mcf per day.

By another order, issued September 26, 1961, in Docket No. CP61–341, the Commission authorized an interconnection between the pipelines of Mississippi Transmission and Mississippi for the purpose of permitting them "to make deliveries of natural gas to each other when such deliveries can assist in their respective system operations and can be made without curtailment or interruption of service to the markets of the party making such deliveries. Under the exchange agreement, the party receiving deliveries thereunder is obligated to return a like quantity of gas to the other party. The exchange of gas will provide added flexibility of operation and continuity of service for both" companies. Accordingly, the Mississippi and Mississippi Transmission systems are now integrated with the common element of ownership. As counsel for Laclede state, "The Commission has always considered the combined Panhandle-Trunkline system as a single entity in determining and allocating customer demands. It would be fully justified in so treating the Mississippi-[Mississippi] Transmission system."

As the evidence shows, the gas supplies represented by Mississippi Transmission's capacity can be made available either directly or, by displacement indirectly, to all of Mississippi's customers.

While Mississippi's President testified at the reopened hearing that he has thought about Mississippi seeking to purchase gas from Mississippi Transmission, he has made no effort to do so. But, as is apparent, if Mississippi had the necessary incentive it could at any time, with a minimum of effort, obtain for its customers any volume of gas Mississippi Transmission's system is capable of delivering, because Mississippi would in truth be dealing with itself. It is sitting on both sides of the table.

Counsel for Mississippi's industrial customers object to any disruption of their dependence upon Mississippi for natural gas service. However, there can be no doubt but that Mississippi, after allocation of Mississippi's presently unallocated capacity to the utility customers, will be in a position to satisfy their claimed needs either directly, or through Mississippi Transmission, if it is willing to do so on terms acceptable to the industrial customers. Thus if there is any disruption of service it will be a disruption for which Mississippi, not the Commission, will be responsible. This is made clear, among other things, by the following testimony of the President of Mississippi Transmission:

Q. If the companies, Illinois Power and Laclede, do not exercise the options to take the additional gas, does your company intend to try to find markets for that gas to sell it?

A. We do.

Q. Are you actively seeking markets to sell your gas, additional volumes of gas, quantities of gas?

A. Yes, sir, we are.

Q. You will sell the gas that Laclede and Illinois Power will not take under their options to other distributing companies or other persons, is that true, sir?

A. It is our intention.

* * * * * * *

Q. Have you approached Mississippi * * * to see if you can sell any of that gas to them * * *?

A. It apparently was not necessary for us to approach Mississippi * * *. There have been discussions between some of Mississippi River Fuel's customers and Mississippi * * * itself which I am advised might result in such a sale.

* * * * * * *

Q. Has anybody from Mississippi * * * ever approached you to try to buy gas from you for their system?

A. They have talked about it.

* * * * * * *

Q. You would have no objection, would you, to selling any excess gas you might have to Mississippi * * *?

A. I cannot answer your question as to excess gas. I would say I will be willing to sell gas to Mississippi * * * or Laclede * * * or Missouri Natural or St. Charles * * * or Union * * * or Illinois Power some additional gas. * * *

Q. Well, if Mississippi * * * industrial customers, as it should turn out, should need some gas, you would not have any objection to selling it to them, would you?

A. Not if we can make money doing it.

Therefore, for the industrial customers to escape the consequences they visualize, all they have to do is duplicate the efforts of Laclede, Illinois Power and St. Charles and assume whatever financial obligation Mississippi requires and that the industrial customers will be able to live with.

No witness was presented at the reopened hearing by any of the industrial customer-interveners.[9] In the absence of testimony from responsible officials of the industrials as to the plans they have been or are making to provide for their future fuel needs, their counsel ask the Commission to assume that the industrial customers cannot get gas from Mississippi Transmission or Mississippi, or both, or from some other source, in the event the Examiner's decision becomes the decision of the Commission—an assumption which seems to be completely contradicted by the above quoted testimony of the President of Mississippi Transmission to the effect that his company is willing to sell gas to both Mississippi and the industrials "if it can make money doing it." In any event, counsel are asking far too much without having undertaken the responsibility of showing that their assumption is a fact. To borrow the words of the Supreme Court in *Runkle* v. *Burnham*, 153 U.S. 216, 225–226, "production of weaker evidence, when stronger might have been produced, lays the producer open to the suspicion that the stronger evidence would have been to his prejudice." Clearly, it was incumbent upon counsel for the industrials to establish the validity of the assumption they make. This is particularly true in this case where a private interest cannot be permitted to override the obligation of a natural gas company to the public interest.

In the circumstances of this case, the Examiner is unwilling to assume that the industrial customers have been unresourceful in protecting their own interest for they have always known of the interruptible character of their gas purchase contracts which can be terminated on six months notice. They have for years known that both the Commission and Mississippi have regarded the utility customers as having a prior claim to Mississippi's capacity, and that in recognition of this fact the Commission has on occasions, including two occasions in the initial phase of this consolidated proceeding, increased the stated demands of utility customers and provided initial service to new utility customers out of Mississippi's capacity. Moreover, since September 13, 1960, they have been aware of the fact that the Examiner's decision now pending before the Commission recommends the allocation of the remaining portion of Mississippi's unallocated capacity to the utility customers. And since September 26, 1961, they have known that Mississippi's system will be interconnected not only with Mississippi Transmission's system but also with the system of Natural Gas Pipeline Company of America (*supra*, p. 763). They are also aware that orders have been, and presumably still are, actively investigating the opportunities of serving gas in the St. Louis area.

The Commission reopened the record for the purpose of taking additional evidence on three factors (*infra*, p. 768), one being "evidence concerning the supplies of gas presently available to Mississippi's various customers." On the basis of the evidence presented the Examiner finds that the Mississippi Transmission system represents a supply of gas which can be made available to all of Missis-

[9] At one point in the reopened hearing the Examiner put counsel for the industrials on notice that if they "put in any evidence in this proceeding, I will be very interested in finding out whether or not your clients have approached Mississippi * * *, what its response was, whether they approached Mississippi [Transmission], what its response was, and if neither of those will supply your clients, whether or not you have gone to the distributors that serve the territory to see what they would do. I think this record ought to show that."

sippi's customers if they are willing to pay the price fixed by the Commission—in the case of utility customers, or exacted by Mississippi—in the case of the industrial customers. If the industrial customers need firm gas, and are willing to contract for it, the purchase of a firm supply from Mississippi Transmission would create no more hardship on the industrial customers than on the utility customers, despite the higher cost of Mississippi Transmission gas. As shown by the abridged hearing set for December 7, 1961, to authorize Mississippi Transmission to sell 1,000 Mcf to St. Charles (*infra*, p. 776), it is a very simple matter for Mississippi Transmission to obtain authorization to provide Mississippi's customers with whatever firm gas they desire to purchase.

While counsel for Mississippi contend that Illinois Power could meet its 1963–64 requirements by introducing gas purchased from Natural Gas Pipeline Company of America into Illinois Power's supply area C, the record shows that this is not at present an assured supply but only a possible source that Illinois Power might have to try to firm up in the event its application herein, which has been pending since March 5, 1959, is denied to enable Mississippi to preserve the present profitability of its industrial sales.

Examiner's Decision Issued December 13, 1960

Following the close of the initial hearing on October 14, 1959, the Examiner issued his decision on September 13, 1960, disposing of the consolidated proceeding other than the two 7(a) applications which were granted by separate prior opinions issued by the Examiner on November 13, 1959 (22 FPC 1039), and July 25, 1960. The history of this proceeding up to September 13, 1960, is set forth in the Examiner's decision issued that date.

The issues upon which the Examiner's initial decision was based were:

> Two related issues * * *. First are the requests for increases in stated demand for existing utility customers. Second is the proposed revisions and additions to Mississippi's tariff to prevent undue prejudice and disadvantage to the utility customers.

These are the issues framed by the Section 7(a) applications and the complaint and by the Commission's order dated May 21, 1959 (21 FPC 701), consolidating these proceedings for purpose of initial hearing and instituting an investigation upon the complaint. In disposing of these issues the Examiner was primarily concerned with this question: What *is* Mississippi's system capacity and *how* should it be allocated? This is still the basic controversy underlying this proceeding. It gets to the root of Mississippi's service-destroying high profit motive which prevented the economy of its service area from achieving its potential for progress and severely impeded the normal expansion and development of the distribution systems of utility customers.

In resolving the related issues the Examiner ordered revisions and changes in Mississippi's FPC Gas Tariff, Original Volume No. 1, upon finding certain provisions of that tariff to be unjust, unreasonable, unduly discriminatory and preferential, and found the actual capacity of Mississippi's system to be 534,000 Mcf per day, as determined by the Commission's staff upon investigation ordered by the Commission, of which only 466,792 Mcf was then allocated to Mississippi's utility customers. The difference of 67,208 Mcf (534,000 Mcf—466,792 Mcf), less 2,640 Mcf,[10] or 64,568 Mcf per day, was allocated on a two-step pro rata basis to the utility customers.

[10] Capacity not allocated to the utility customers was 2,000 Mcf for pilot light service for Mississippi's industrial customers and 640 Mcf for the City of Red Bud, Illinois, for initial service.

The decision also directs Mississippi to file applications for certificates of public convenience and necessity for authority to continue (1) the operation of all facilities comprising its system for which it has not heretofore made application to construct and operate, and (2) service to such industrial customers as it was not serving on the effective date of its "Grandfather" certificate.

Commission Authorization of Construction and Operation of Mississippi Transmission's System

Following the close of the hearing on which the Examiner's decision of September 13, 1960, was based, Mississipi, by maintaining its unyielding position, progressed towards its goal of "The new subsidiary or nothing." In a new and separate proceeding which commenced on September 7, 1960, and concluded on October 2, 1960, the Commission authorized Mississippi Transmission to construct, own and operate the system recently placed in operation to deliver additional gas to the St. Louis area from a Johnsonville, Illinois, connection with the initial delivery to be 50,000 Mcf per day, of which 42,500 Mcf was to be delivered to Laclede and 7,500 Mcf to Illinois Power. This authorization was part of the authorization contained in the Commission's Opinion No. 339 issued November 29, 1960, after the issuance, 24 FPC 1020, of the Examiner's decision on September 13, 1960. In Opinion No. 339 the Commission observed that the additional 50,000 Mcf per day initially made available through Mississippi Transmission's system would "help relieve the longstanding and rather acute deficiencies in gas supply in the areas served by Laclede and Illinois Power, particularly in the St. Louis area."

Mississippi's Petition To Reopen the Record

Following the issuance of the Commission's Opinion No. 339 on November 29, 1960, as amended on December 14, 1960, to eliminate the St. Jacob Storage Project (24 FPC 1068), Mississippi, on January 10, 1961, filed its petition requesting the Commission to reopen the record for the purpose of receiving additional evidence, the ground for which being that changes of fact, relating primarily to Laclede, Illinois Power, MidSouth and St. Charles, "have occurred since the conclusion of the hearing which are compelling materiality." According to the petition, the changes of fact had "completely destroyed the 'gas shortage' as a basis for decision herein" and that, consequently the utilities no longer have need for the increase in the stated demands allocated to them by the Examiner * * *."

Mississippi, in support of the allegations made in its petition to reopen the records, offered to adduce evidence showing (1) that Mississippi Transmission's system would substantially increase the natural gas supplies available to Laclede, Illinois Power, and St. Charles; (2) that Laclede and Illinois Power had contracted to purchase 50,000 Mcf initially from Mississippi Transmission with options allowing increases up to 75,000 Mcf on December 1, 1962, and up to 100,000 Mcf on December 1, 1964, subject to certain conditions pertaining to Trunklines' reserves; (3) that Trunkline had expressed its willingness to accelerate the quantity increases called for by the options held by Laclede and Illinois Power; (4) that Mississippi believed that negotiations between St. Charles and Mississippi Transmission would produce a definitive arrangement, indicating that Mississippi Transmission would supply St. Charles with the additional gas it needs; (5) that effective October 3, 1960, Mississippi increased MidSouth's stated demand by 3,350 Mcf, such increase being made possible by the voluntary release of gas by another utility customer of Mississippi; (6) that Mississippi could produce geological evidence supporting the optimistic

view that the additional storage area of the Roubidoux formation in Laclede's Lange Storage Field, now in the process of development, will be capable of peak day deliveries of at least 37,000 Mcf by the 1961–62 heating season and of at least 177,000 Mcf during the 1964–65 heating season; and (7) that the reopening of the record would also permit it to offer evidence of the development of Mississippi's St. Jacob storage field then in an exploratory stage.

Laclede, Illinois Power and MidSouth strongly objected to the reopening of the record. Each emphatically denied that the factors relied upon by Mississippi had or would satisfy their gas needs. St. Charles agreed to the reopening of the record only if the Commission by interim order granted part of the relief requested in its application, which request was denied.

Laclede opposed the granting of Mississippi's petition on the ground that the alleged changes of fact were matters of which the Commission could take official notice and that, in any event, the alleged changes were not material because it is Mississippi's gas sales and capacity and not that of its customers that is on trial. Counsel for Laclede expressed the view that Mississippi's petition represented "but another effort to delay further the long overdue day of reckoning. It * * * is based in large measure upon speculation. It ignores the real issue * * * and is founded on the erroneous premise that 'gas supply,' regardless of price and regardless of law and equity, was the only reason for Laclede's Complaint and was the sole issue in the many days of hearings." "Mississippi continues to make every effort to avoid its responsibility to supply Laclede's requirements and appears willing to do everything possible to perpetuate its irresponsibility." "The most persuasive and relevant evidence concerning other sources of supply for Laclede could have but little bearing on how Mississippi's capacity is to be allocated equitably among its customers through revision of its tariff." "The Examiner recognized the real issues and especially the important bearing on them of the provisions of Mississippi's tariff in which he ordered * * * changes * * *." "Laclede entered into the agreement to purchase Trunkline gas only after some four years of negotiations with Mississippi and following Mississippi's repeated refusal to meet its obligations to Laclede's full requirements contract. The record in the *Trunkline* case is clear that Laclede has always preferred to have its requirements met—as by contract they are supposed to be met—by Mississippi * * *; that this is the basic source of supply upon which it must rely. The agreement to purchase Trunkline gas through Mississippi's affiliate (Mississippi Transmission) was entered into only as a last resort * * *." "The Trunkline gas is small in volume (only 85,000 Mcf per day after both options are exercised). Its price is substantially in excess of that paid by Laclede to Mississippi. While Laclede needs this gas and plans to make as much of it as possible—even on an accelerated basis—this represents but a partial solution to Laclede's overall gas supply problem." "Laclede would not be able to present any evidence other than of a speculative nature on [the Roubidoux storage aspect of Laclede's gas supply picture]; we are sure Mississippi could not."

The Commission's Order Reopening the Record

By its order issued March 27, 1961, the Commission determined that the record should be reopened. As reasons for so doing it stated:

> Considering the arguments for and against reopening we are of the opinion that in the circumstances of this case the public interest will be best served by reopening the proceedings. We believe the changed circumstances which have occurred since the Examiner considered this matter and the issues involved should be decided upon as complete a record as possible.

> It appears that as a result of the certifications granted [Mississippi] Transmission * * * supplies of gas available to Laclede and Illinois Power will be augmented by some 50,000 Mcf per day. There is the further possibility that gas from [Mississippi] Transmission may alleviate St. Charles' dilemma. The development of storage areas also gives rise to the possibility of further amelioration of the St. Louis area's gas supply problems. The Commission is aware that issues other than gas supply are of equal importance in these proceedings, and we are of the opinion that an augmented record containing the additional evidence concerning the matters referred to above may be of such significance as will affect the disposition of these proceedings, and therefore that the public interest demands the introduction of such evidence into the record.
>
> In the present posture of these proceedings the Commission is of the opinion that the record is inadequate to make a fair and reasonable determination of what changes, if any, may be required to be made in Mississippi's tariff to allocate its system capacity among all customers served. In order to make such determination, it appears that it will be necessary to have in the record information concerning the present and estimated future requirements of all customers served by Mississippi, including those customers which presently are not parties to the proceedings. In order to make a fair and reasonable allocation consideration must be given to the comparative needs for gas. The present record is inadequate to weigh comparative needs.

The Examiner construes the above quoted language as providing only for bringing the record down to date so that the issues can be decided on as complete a record as possible—not as indicating an intention on the part of the Commission to provide the industrial customers with rights superior to either their contract rights or the rights of the utility customers. As the Examiner stated in his decision, "the rights of the parties are fixed by the terms of the previously executed contracts and [the industrial customers] should not be permitted at this late date, when the utility customers are seeking increases in their stated demands, to acquire a status superior to that of the utilities."

Additional Evidence Required by Commission's Order and Examiner's Ruling at Reopened Hearing

The Commission's order reopening the record required that additional evidence be taken on three factors:

(a) The relative need of the various utility customers of Mississippi for gas from pipeline capacity available to Mississippi.

(b) The changes, if any, required in Mississippi's tariff pertaining to the establishment of priorities of service between direct and resale customers.

(c) The supplies of gas presently available to Mississippi's various customers.

Because of allegations contained in Laclede's response to Mississippi's petition to reopen the record to the effect that at the time Mississippi's subsidiary was considering whether or not to accept the certificate issued in Opinion No. 339, Mississippi's President attempted to convince Laclede that Mississippi Transmission might not accept the certificate and serve the additional gas unless Laclede withdrew its Section 5(a) complaint in the instant proceeding, the Examiner, at the outset of the reopened hearing called upon—

> * * * Mississippi, Laclede and Illinois Power, and any other parties which have knowledge of the facts and desire to do so, to set forth on this record, through the testimony of a responsible representative of each company, what took place following the close of the record in this proceeding on October 14, 1959, which caused Laclede and Illinois Power to agree to pur-

chase the additional 50,000 Mcf through Mississippi's subsidiary, and what caused the president of Mississippi to attempt to convince Laclede that Mississippi's subsidiary might not accept the certificate and serve the additional gas unless Laclede withdrew its Section 5(a) complaint herein. Such evidence is essential to a forthright determination of the basic controversy underlying these proceedings.

In response to the Examiner's inquiry as to Laclede's allegation as to the efforts of the President of Mississippi to get Laclede to withdraw its Section 5(a) complaint, the President of Mississippi testified that he did not threaten the representatives of Laclede and Illinois Power but—

> * * * simply asked them if they would be willing to withdraw their 5(a) and 7(a) applications their companies had filed in the event Mississippi * * * Transmission * * * decided to refuse to go ahead with its pipeline project in the absence of such a withdrawal.

Laclede's President testified that his recollection of the conversation was that Mississippi's President inquired if—

> * * * we [Laclede and Illinois Power] would be willing to withdraw the 5(a) and 7(a) applications, respectively, * * * as a condition of Mississippi River Transmission accepting the certificate which had been issued. * * * And he said that unless we did, he thought he would have difficulty in getting his Board to let him accept that certificate.
>
> Now * * * about the question of whether he threatened us. I don't consider that a threat, but I do think it was an effort to persuade. And we both turned it down.

Reopened Hearing Procedure

Following a conference held on the record on April 18, 1961, seven days of additional hearings were held commencing May 31 and ending July 26, 1961, at which time evidence was presented with respect to the above mentioned factors set forth in the Commission's order of March 27, 1961. At the conclusion of the reopened hearing the Examiner fixed September 6 for the filing of simultaneous main briefs and September 20 for the filing of simultaneous reply briefs.

Main and reply briefs have been filed by counsel for Mississippi, Laclede, Illinois Power, MidSouth, St. Charles, Missouri Natural Gas Company, Owens-Illinois Glass Company, Obear-Nester Glass Company, American Brake Shoe Company, Lewin-Mathes Company, Missouri Rolling Mill Corporation, Alton District Manufacturers' Association, Granite City Steel Company, American Steel Foundries, American Zinc Company of Illinois, The Dow Metal Products Company, Laclede Steel Company, Olin Mathieson Chemical Corporation, National Lead Company, Pittsburgh Plate Glass Company, and C. K. Williams & Company. Commission staff counsel filed a summary-type main brief but no reply brief.

Applications and Complaint Involved Herein

Two of the applications involved in the initial hearing (filed by Natural Gas Improvement District No. 2 of Ashley County, Arkansas, in Docket No. G–17942 and by the City of Red Bud, Illinois, in Docket No. G–16504), filed under Section 7(a) of the Act, have been severed from the consolidated proceeding and granted by opinions and orders which have become final. Accordingly, there are now involved in this proceeding (1) the three Section 7(a) applications for increased stated demands filed by Illinois Power, MidSouth Gas Company (MidSouth), and St. Charles, and (2) the investigation instituted by the Commission upon the Section 5(a) complaint filed by Laclede.

In addition to the complaint and the 7(a) applications above referred to, there are other utility customers of Mississippi, namely Union Electric Company (Union), Missouri Natural Gas Company (Missouri Natural), the Village of Dupo, Illinois (Dupo), Public Utility Company of Crossett, Arkansas (PUC Crossett), and Natural Gas Improvement District No. 2 of Ashley County, Arkansas (Ashley County), which are seeking comparable relief.

Laclede's Complaint. Laclede's stated demand of 330,000 Mcf has not been increased by Mississippi since 1955. It filed its complaint on February 13, 1959, after extended negotiations with Mississippi for additional gas supplies and following Mississippi's repeated refusal to meet its obligations under Laclede's full requirements contract. The complaint seeks not only a fair and equitable allocation of Mississippi's overall system capacity among Mississippi's utility customers, but also relief from the provisions of Mississippi's tariff and practices of Mississippi thereunder, to which the Examiner has, in his decision issued September 13, 1960, found the utility customers to be entitled.

Laclede's estimated requirements for 1961–62, totaling 690,000 Mcf, give effect to the assumption that it will receive the additional 45,647 Mcf per day which the Examiner's decision of September 13, 1960, allocates to it:

	Mcf	
Peak day requirements		690,000
Peak day supply:		
Mississippi (present 330,000 plus 45,000)	375,000	
Purchase from other pipeline (Mississippi Transmission)	64,000	
Company produced gas	95,000	
	534,000	
Receipts from storage (balance)	156,000	
	690,000	690,000

Counsel for Mississippi attempt to minimize Laclede's need for additional gas by contending that Laclede's Lange storage is capable of delivering volumes of gas in excess of those now estimated by Laclede to be deliverable. Their challenge is based on two grounds:

(a) that the St. Peter formation is not being utilized to the maximum extent possible; and

(b) that the Roubidoux formation in that field will be able to supply greater volumes of gas on a peak day—and sooner—than Laclede has indicated.

Before considering these two grounds, two other factors of importance should be mentioned. First is the fact that the methods utilized in meeting peak deliveries of gas from storage are generally the most economical of all known methods. There is no reason to believe that Laclede would seek to buy additional pipeline gas if it could meet its peak day requirements from its own storage. Laclede is here seeking additional pipeline gas from Mississippi at about 25 percent load factor, and it appears that even under Mississippi's relatively favorable rates, it would be expensive, costing about 47 cents per Mcf. Laclede estimates that if purchased from Mississippi Transmission it would be twice as expensive, after giving effect to its 75 percent load factor minimum take or pay provisions and consequent reduction in volumes purchased from Mississippi. As counsel for Laclede state in their brief, "all argument on the subject becomes rather meaningless when it is recognized that Laclede would be irresponsibly wasteful if it were to buy firm pipeline gas at 25 percent load factor if it could meet its demand with gas from its own storage."

Second, the record shows that Mississippi Transmission is anxious to sell Laclede more gas and it does not appear that any opposition has ever been registered by Mississippi to it doing so. In fact Mississippi is anxious for Laclede to again turn to Mississippi for its additional needs. From this it is reasonable to conclude that Mississippi's contentions here are really not based upon a belief that Laclede does not need and cannot sell the additional gas, but upon what has been evident since 1956, namely, that Mississippi's efforts are directed to preserving the present profitability of its industrial sales at the expense of the general public.

In their attempt to show that Laclede is understating its storage deliverability, counsel for Mississippi rely upon estimates which were made by Laclede prior to the operation of the 1960–61 winter. They seek to have the conclusion drawn from such earlier estimates and the general knowledge of their witness—rather than current performance data—that Laclede's Lange storage is capable of delivering volumes of gas in excess of those now estimated by Laclede to be deliverable, particularly for 1961–62.

Laclede readily admits that its estimates of Lange's deliverability have been revised downward, an action which is understandable because it was caused in the main by the fact that, during the past winter, 1960–61, the pressures in the field declined to the point where a continuation of cold weather would have rendered Laclede unable to meet its commitments to its customers. Laclede's current appraisal of its storage potential, based upon a detailed study made on a day to day basis by a qualified engineer who has lived with the Lange project since its inception, must be given far greater weight than its prior appraisals and the generalized knowledge of underground storage projects and a preliminary study made in 1954 (before storage of gas in the Lange Field)—upon which Mississippi's witness drew his conclusion that Lange can produce greater quantities of gas than Laclede contends is possible.[11] Mississippi's witness testified that he had "never gone into the [Lange] field and done any pressure or physical testing" himself. Staff counsel describes the opinion given by Mississippi's witness as "considered conjecture."

Laclede, in its response to Mississippi's petition to amend the record pointed out that, because Roubidoux—an acquifer storage—is in the early and experimental stages, Laclede would not be able to present any evidence other than of a speculative nature concerning the possibilities and potentialities of Roubidoux, and that it was sure Mississippi could not (*supra*, p. 768). The record bears out Laclede's contention.

As Laclede's President testified (*supra*, p. 757), if the 45,647 Mcf of additional gas which the Examiner has allocated to Laclede from Mississippi's pipeline is not made available from Mississippi, Laclede "will have to get an equivalent volume of gas somewhere else. As Mr. Liberman's testimony shows, we need this gas and after that we still need more gas." After pointing out that the 45,647 Mcf would cost $3,800,000 a year if purchased from Mississippi, the President of Laclede further testified:

> PRESIDING EXAMINER: * * * I want to ask you this question in connection with that amount of money, * * * would you have any part in recommending to your company or recommending your company to incur that amount of money if you could not recover it through the sale of gas?
>
> THE WITNESS: No, sir, I would be derelict and most certainly, when we enter into an agreement over a long period of time, obligating ourselves for

[11] 200,000 Mcf on the peak day in 1961–62 as compared with Laclede's estimate of 156,000 Mcf.

the demand cost as well as the future rate increases which may or may not be forthcoming as a result of action by this Commission, I would have to be very certain that we could market that gas. But there is a market that Mr. Liberman didn't even touch on.

PRESIDING EXAMINER: What market is that?

The WITNESS: We have, for example, * * * hotels and hospitals that operate like that on an interruptible basis which should not be that way. They should have firm services, but we have not even figured on them. They have been getting along reasonably adequately, but they would prefer firm service and I am sure they would pay for it if we could make it available to them, but we are going to take care of these others first.

* * * * * * *

The WITNESS: * * * But apartment houses and hotels, hospitals, many on other fuels at this time, would like to go on firm gas. They won't take interruptible because of the bother and the labor problem, all those things in addition to what Mr. Liberman has shown exists in the market place, in his opinion, add up to my view that we can use all this gas and then some."

As counsel for Laclede point out in their brief, "Laclede's house-heating saturation remains the lowest of any major city in America, being slightly over 60% * * *. Despite only minimal efforts to sell gas—more in the nature of institutional advertising than in the nature of a selling campaign—Laclede has long waiting lists on file of those wanting gas for house-heating purposes * * *. As a matter of fact, Laclede has been operating since 1950 under restrictions against the addition of space heating load. The record clearly demonstrates, therefore, that Laclede and the public require not only the new [Mississippi] Transmission gas but also the additional [Mississippi] gas allocated to it by the Examiner's Decision * * *." As they further point out, "In the face of such clear and truly uncontroverted evidence of genuine need for gas, the dollar oriented attitude of Mississippi seems especially shocking. * * * While storage is important and essential—including the development of additional storage—it is not the sole long-range answer to Laclede's supply problem."

There can be no question but that Laclede needs the gas allocated to it in the Examiner's decision issued September 13, 1960, if it is to have reasonable expansion and if the public, rather than Mississippi's private interest, is to be served.

Illinois Power's Application. Illinois Power's application was filed on March 5, 1959, for an order directing Mississippi to sell and deliver to Illinois Power 12,000 Mcf of natural gas per day in addition to the 57,202 Mcf per day that Mississippi is presently authorized to deliver to Illinois Power during the on-coming heating season (1961–62).

During the reopened hearing Illinois Power amended its application filed March 5, 1959, from an additional 12,000 Mcf per day to an application for 17,548 Mcf per day, to conform to the evidence presented, such evidence demonstrating Illinois Power's requirement for 17,548 Mcf, or an increase in stated demand from 57,202 Mcf per day to 74,450 Mcf per day, beginning with the 1963–64 heating season. The Vice President of Illinois Power testified that he has indicated to other pipelines proposing to come into the area that Illinois Power desires to purchase an additional 10,000 Mcf per day for the 1962–63 season because Illinois Power needs further protection for that winter; that the avail-

able "supplies as shown in Exhibit 97 are very close to our estimated market needs. And while that is our projection of our needs, our commercial and sales organization tells us and feel that they are too conservative, that they will be able to sell more gas, particularly for space heating, in that area, and that our requirements are perhaps understated."

Illinois Power, as hereinabove noted (*supra*, pp. 762–763), originally contracted to purchase 7,500 Mcf per day from Mississippi Transmission, delivery of which began on May 10, 1961. After the reopening of the record Illinois Power contracted for additional gas from Mississippi Transmission, so that commencing December 1, 1961, it will receive from this company a total of 11,250 Mcf per day.

Counsel for Mississippi speculate that Illinois Power "by availing themselves of the option from [Mississippi] Transmission * * * could obtain an additional 3,750 Mcf from that company in that year under existing arrangements * * *. Furthermore, they could undoubtedly get the entire 17,548 Mcf from Transmission by the 1963–64 season, if they chose to arrange for it, in view of Transmission's capacity and other evidence * * *." No good reason is shown why Illinois Power should purchase Mississippi Transmission's higher cost gas, even if the options were firm in all respects, if there is lower cost Mississippi gas available. Nor is there any reason why Illinois Power and the other utility customers should be required to bear the entire additional burden in price, and to pass that burden on to their retail customers.

Counsel for Mississippi suggest another alternative source for meeting Illinois Power's requirements, namely, introduction of gas to be purchased from Natural Gas Pipeline Company of America, which might be made available to Illinois Power through the construction of about two and a half miles of additional pipeline—pipeline construction which would be unnecessary if the desired volume is made available through Mississippi's existing interconnection with Illinois Power's system.

The evidence makes it clear that unless Illinois Power can obtain further commitments from Mississippi, it will attempt to connect Natural Gas Pipeline Company of America's line to Illinois Power's Supply Area C. In carrying out its public utility responsibility, and in making its contribution to the economic growth of its service area, Illinois Power attempts to make its plans sufficiently in advance to take care of the needs of those in its service area whenever it is possible to do so in the public interest. This cannot be said of Mississippi.

The forced use of the alternative methods suggested by Mississippi for meeting Illinois Power's requirements—assuming that in fact they could be firmed up—would be justified only if it could be shown to be in the public interest. Such a showing would be impossible for use of either or both alternatives would be detrimental to the public interest. This is so because the purpose of using the alternative methods would be to preserve the present profitability of Mississippi's industrial sales at the expense of the general public. Mississippi's attempt to preserve the magnitude of its present profits has been greatly destructive of the public welfare and ought not to be continued.

MidSouth's Application. MidSouth's application, filed January 19, 1959, sought an increase of 3,000 Mcf in its stated demand, or from 22,790 Mcf to 25,790 Mcf, by November 1, 1960, for service on peak days to domestic and commercial customers.

After the closing of the initial record and before its reopening, Mississippi increased MidSouth's stated demand by 3,350 Mcf, effective October 3, 1960. This increase was the first increase in MidSouth's stated demand since 1952 and appears to have been accomplished by the voluntary release of gas by

Arkansas Louisiana Gas Company, another utility customer of Mississippi.

One of the "changes of fact" upon which Mississippi relied in its petition to reopen the record was that the need for an increase in MidSouth's stated demand had been satisfied because it had received the 3,350 Mcf of natural gas which had been released by Arkansas Louisiana Gas Company. In opposing Mississippi's petition to reopen the record, MidSouth stated that "Mississippi filed the change in its tariff to reflect this increase in MidSouth's Stated Demand by a letter dated August 30, 1960. And in this letter which gave the reasons for the proposed changes in the Stated Demands of MidSouth and several other customers, no allegation was made by Mississippi that the increase to MidSouth was to be in lieu of, and in complete satisfaction of, the 3,000 Mcf increase that MidSouth is seeking in the instant proceeding. In fact, no reference was made in any way to the instant consolidated complaint—7(a) proceeding. Therefore, Mississippi must have considered the reallocation of the gas released by Ark-La. as being unrelated to MidSouth's 7(a) application."

With but one very minor exception,[12] MidSouth has no firm industrial contracts and, hence, service to its industrial customers is fully interruptible.

MidSouth's present stated demand is 26,140 Mcf. Because the firm requirements of connected customers are now in excess of this stated demand, it is in need of additional gas and finds itself in the position of being forced to overrun its stated demand and pay heavy penalties. During the 1960–61 winter MidSouth's actual total peak day requirement was 28,951 Mcf. On that day (January 24, 1961) MidSouth curtailed deliveries to its interruptible industrial customers by 5,821 Mcf, but nevertheless overran its stated demand of 26,140 Mcf by an amount of 2,811 for which it paid Mississippi $20,110 in penalties. It was also required to take penalty gas on three other days in the past winter to meet the needs of its connected customers.

MidSouth has had extensive studies conducted looking toward the development of underground storage, but no known storage possibilities have been found in the territory served by MidSouth. It purchases gas from Mississippi at 17 separate delivery points, and because of this and as the dilution of natural gas by a propane-air mixture is limited, it becomes very difficult for MidSouth to construct and operate propane-air peak shaving equipment on a reasonable basis.

The evidence offered by MidSouth supports the reasonableness of its estimated peak day requirements through the 1963–64 heating season, namely, a need for 4,860 Mcf for the oncoming heating season, and additional increases of 1,000 Mcf each year for the next two years. It is therefore requesting an increase in its present stated demand of 26,140 Mcf per day to a stated demand of 31,000 Mcf for the 1961–62 heating season, 32,000 Mcf for the 1962–63 heating season and 33,000 Mcf for the 1963–64 heating season.

The Examiner finds no justification for the contention of counsel for Mississippi that the testimony of the President of MidSouth in the reopened record indicates that MidSouth does "not desire to have its stated demand increased."

St. Charles' Application. St. Charles' application filed April 28, 1959, requests an order directing Mississippi to increase St. Charles' stated demand from 2,360 Mcf to 3,686 Mcf by November 1, 1959, to 4,289 Mcf by November 1, 1960, to 4,865 Mcf by November 1, 1961, and to 5,287 Mcf by November 1, 1962, and to 5,651 Mcf by November 1, 1963, or by a total of 3,291 Mcf per day over the five-year period. The application filed by St. Charles, as amended, was based upon

[12] MidSouth has a contract with the Remington Rand Corporation which provides for a maximum delivery of three Mcf per hour but this company does not take firm gas every day and did not take gas on the peak day of January 24, 1961.

St. Charles obtaining all of its supplies from Mississippi, exclusive of approximately 460 Mcf of peak shaving to be produced by St. Charles.

In opposing Mississippi's petition to reopen the record, counsel for St. Charles pointed out that "St. Charles, having a duty to serve its growing market but having received no increase since February 1, 1959, in its Stated Demand allotment of 2,360 Mcf per day, during the current winter season is being required to pay to Mississippi substantial penalties at $2 per Mcf of gas taken in excess of 2.360 Mcf per day. The penalties have been and are being incurred as this is written * * *."

In its application to reopen the record Mississippi stated that it believed that negotiations between St. Charles and Mississippi Transmission would produce a definitive arrangement, indicating that Mississippi Transmission would supply St. Charles with the additional gas it needed. By the time the reopened hearing commenced on April 18, 1961, St. Charles had entered into an agreement to purchase 1,000 Mcf of gas per day from Mississippi Transmission, contingent upon certain conditions including authorizations by the Commission being granted in Trunkline's Docket No. CP62–46 and in Mississippi Transmission's Docket No. CP62–48 which have been consolidated and set for hearing on December 7, 1961, under the Commission's shortened procedure rule.

As the record clearly shows, St. Charles has need for the 1,000 Mcf per day to be obtained from Mississippi Transmission and substantially more—namely, 628 Mcf per day more for the on-coming winter, an additional 772 Mcf per day more by November 1962, and an additional 922 Mcf per day more by November 1963.

In the following excerpt from the reply brief of counsel for St. Charles, with which the Examiner is in complete agreement, counsel for St. Charles correctly and successfully challenge not only the unfounded statement in the brief of counsel for Mississippi to the effect that St. Charles and the other utility customers "have admitted on this record that gas supply is no longer a problem" but also other contentions made by counsel for Mississippi with respect to the request of St. Charles herein and the situation with respect to which St. Charles is faced:

> St. Charles has nowhere "admitted on this record that gas supply is no longer a problem", but, rather, it has consistently requested the additional supplies needed by it and supported its request with clear evidence of its need.
>
> Mississippi's brief in other respects fails to do justice to St. Charles' needs. For example * * * it attempts to summarize the increased volumes of gas requested by St. Charles, but, in so doing, quotes volumes substantially below those requested and substantiated by St. Charles.
>
> By commencing with this understatement of the increases in Stated Demand requested by St. Charles, then by adding in the 1,000 Mcf per day of higher-priced gas for which St. Charles has contracted from Mississippi's subsidiary, Mississippi * * * Transmission * * * and by eliminating certain requirements estimated by St. Charles in its existing market area, Mississippi in its brief concludes that St. Charles' supply problem has been solved and its application should be denied. Conversely, we submit that St. Charles' attempt partially to relieve its immediate shortage by contracting for the higher-priced gas from Mississippi * * * Transmission * * * is the clearest possible indication of the serious nature of its short supply. Additionally, in the time between the 1959 and the 1961 hearings, in a further effort to relieve its short-supply situation, St. Charles nearly doubled its peak-shaving capacity. Accordingly, St. Charles is confident that neither the

Presiding Examiner nor the Commission will reach the conclusion suggested by Mississippi.[2]

Requests of Other Utility Customers Served by Mississippi. Two of Mississippi's utility customers, namely, Union and Missouri Natural, intervened in this proceeding for the purpose of requesting that if it is determined that additional capacity exists on Mississippi's system, they should be allowed to share in the allocation of such additional gas. In submitting the information requested by the Staff's questionnaire, three other customers of Mississippi—Dupo, PUC Crossett and Ashley County—indicated a need for additional quantities of flow gas to meet their peak day requirements. The present stated demands and indicated needs for these five utility customers for the periods shown are:

Customer	Stated demand (Mcf) [1]	1961–62	1962–63	1963–64
Union	10,000	14,385	16,446	16,793
Missouri Natural	24,000	33,700	34,300	34,900
Dupo	675	1,118	1,191	1,267
PUC Crossett	2,000	3,260	3,284	3,313
Ashley County	374	818	848	878

[1] Stated demands shown are those set forth in Mississippi's effective FPC Gas Tariff. Indicated needs for 1961–62, 1962–63, and 1963–64 have been converted to 0° F.

The increases in stated demand sought by Missouri Natural are supported by the testimony of the company's Vice President. However, no witness appeared on behalf of Union, Dupo, PUC Crossett and Ashley County. Accordingly, the only evidence as to the requirements of these four customers is found in their responses to the Staff questionnaire.

Missouri Natural, a full requirements customer of Mississippi, has not received an increase in its stated demand since October 1, 1955. In the past it has been able to provide the service it has provided in its service area only by taking gas at penalty rates from Mississippi.

The Commission's staff recommends that the stated demand of Missouri Natural be increased by 9,700 Mcf per day, or up to the needs shown for the 1961–62 heating season. Counsel for Mississippi take the position that Missouri Natural "should continue, as it has in the past, to purchase overrun gas on the few days in the winter when it needs it to meet its peak requirement * * *." Counsel for Missouri Natural disagree, and properly so, for the following reasons set forth in their reply brief:

> Mississippi * * * intimates that Missouri Natural is better off paying for penalty gas. This is a good idea for Mississippi but is not good for Missouri Natural's customers. Mississippi follows this by saying that if Missouri Natural's stated demand were increased by 9,700 mcf as proposed by the Staff, its demand charge would be increased approximately $228,000.00 annually, as against an eight-day penalty charge for 1960–1961 of $110,700.00. What Mississippi did not say, however, is infinitely more material and important. That is the fact that Missouri Natural is exposed

[2] Contrary to what Mississippi suggests * * *, the primary industrial customer of St. Charles is not a "recently-acquired industrial load." We are advised that this industry, until it moved to the City of St. Charles four years ago, had been supplied by Laclede * * * in St. Louis since 1918.

Additionally, the housing development to which Mississippi objects as not having been certificated * * *, has been certificated in St. Charles' service area and construction commenced.

to penalty gas equal to $862,400,000 based upon a season as severe as the 1939–40 heating season, and $463,800.00 in a season as cold as the 1950–1951 heating season. In an attempt to alleviate its exposure to catastrophic charges for penalty gas, Missouri Natural considered the effect upon its costs of stated demand gas from Mississippi Transmission, but concluded that it would be premature, imprudent, improvident, and against the best interest of its customers to take any gas from Mississippi Transmission. To illustrate, only 2,000 mcf of stated demand gas from Transmission under its existing rates would cost Missouri Natural approximately $200,000.00, or almost as much as the 9,700 mcf increase in stated demand would cost from Mississippi * * *. Moreover, Missouri Natural's exposure to penalty gas would be virtually eliminated with 9,700 mcf increase from Mississippi * * *, whereas with 2,000 mcf or even 4,000 mcf (at a cost of approximately $400,000.00) stated demand from [Mississippi] Transmission, Missouri Natural would continue to be exposed to heavy and onerous penalty gas charges since its total stated demand would continue to be inadequate to meet its peak loads and to expand the service it renders in the public interest."

Insofar as Mississippi's utility customers now seeking gas in this proceeding are concerned, the Examiner's decision issued September 13, 1960, grants increases in stated demand on a pro rata basis, effective December 1, 1961, as follows:

	Present stated demands (Mcf)	Increase granted (Mcf)	Stated demands as of 12-1-61 (Mcf)
Laclede	330,000	45,647	375,647
Illinois Power	56,323	7,791	64,114
MidSouth	22,790	3,152	25,942
St. Charles	2,369	326	2,686
PUC Crossett	1,900	2,031	2,163
Dupo	675	722	768
Missouri Natural	24,000	25,660	27,320
Union	10,000	1,383	11,383
Ashley County	374	52	426

The additional quantities of gas were ordered, subject to review by the Commission, to be made available in two steps, that is one-half on the effective date of the final order of the Commission herein and the other half on December 1, 1961. Use of the pro-rata basis of allocation was caused by the inadequacy of Mississippi's capacity to support an increase in the stated demand of each resale customer to the extent desired by such customers.

Authority of Commission Under Section 7(a)

Section 7(a) of the Act confers jurisdiction upon the Commission to require extensions of service whenever the Commission finds that such action will place no undue burden upon the company. It further provides:

> That the Commission shall have no authority to compel * * * such natural-gas company to * * * sell natural gas when to do so would impair its ability to render adequate service to its customers.

Mississippi and its industrial customers argue that the industrial loads served by Mississippi constitute present service rendered by Mississippi in the same sense that the utilities are present customers of Mississippi, and that it would be unlawful for the Commission to further increase the stated demands of the

utility customers because it would impair Mississippi's ability to render adequate service to its existing industrial customers. While the lack of merit of this contention is shown in the Examiner's decision issued on September 13, 1960, the matter will nevertheless be considered here.

The argument advanced by Mississippi and its industrial customers ignore several facts. First, that the Commission on several occasions has carried out the intent of Section 7(a) of the Act in restricting deliveries to Mississippi's industrial customers not only by increasing the stated demands of existing customers but also by directing Mississippi to provide initial service to new utility customers. Second, that both Mississippi and the Commission have always recognized that, insofar as Mississippi's capacity is concerned, the rights of the utility customers are superior to the industrial customers. Third, that Mississippi's contracts with its industrial customers provide only for interruptible service and are cancellable on six months notice. Fourth, that as the Examiner stated in his opinion issued July 25, 1960, in *City of Red Bud, Illinois, Docket No. G–1650*, in allocating part of Mississippi's capacity to the City of Red Bud over Mississippi's objection—following the initial hearing herein:

> "Adequate service" in the light of the circumstances and facts in this proceeding connotes the ability of Mississippi to satisfy the requirements of its utility customers every day throughout the year. It further connotes the ability of Mississippi to satisfy the requirements of all existing customers and those authorized by the Commission to be added throughout the year, except, if necessary, during peak periods. Deficiencies which may occur, if any, are to be met by industrial curtailment, which is the usual and normal practice in the industry, as explained in [*Manufacturers Light & Heat Co.* v. *F.P.C.*, 206 F. 2d 404] * * *.
>
> * * * * * * *
>
> Mississippi's attempt to equate "adequate service" as that term is used in Section 7(a) with the demands of its industrial customers rather than to the volumes it is contractually obligated to deliver to them is wholly without merit. The order herein does not take gas away from anyone. It permits the maintenance of adequate service to existing customers, and provides the additional service which has been shown to be necessary and desirable in the public interest. This is an exercise of the Commission's prerogative under the Act to require service, making it impossible for Mississippi to veto the authority granted to the Commission.

Fifth, that while Mississippi and its industrial customers are concerned about threatened impairment of service, the fact is that they seek preferential treatment over the utility customers, whose impairment of service has been a grim reality, not just a threat, because Mississippi has continuously and consistently failed to meet their requirements. To offset such impairment of service in part, Laclede and Illinois Power have developed their own manufacturing and storage facilities and have purchased additional high-cost pipeline gas from Mississippi Transmission, and the same is true of St. Charles except that it does not have storage facilities. These steps the industrials have themselves not yet taken. In the face of Mississippi's unwillingness to correct the obviously unsatisfactory supply situation in its service area, it would seem clear that the hazards and disadvantages of impairment, including the higher costs of effecting complementary supplies of gas, should be shared by all, including Mississippi and its industrial customers. Sixth, that the Chief Executive Officer of Mississippi has always been aware of the fact that the existing utility customers could obtain increases in their stated demands by filing Section 7(a) applications. This

is shown, among other things, by the testimony of a Vice President of Illinois Power at the initial hearing:

> Q. Now, were there other matters discussed at this meeting * * *?
>
> A. Yes, we discussed our 7(a) proceedings against [Mississippi] to obtain gas for the towns of Millstadt, O'Fallon and Hamel.
>
> [The Chief Executive Officer] told me that if we and his other purchasers —that is utility purchasers, continued to nibble away at his existing pipeline capacity through this sort of 7(a) proceedings, it was probably our idea that we could do so at the expense of his direct customers.
>
> He stated that he intended to continue these direct sales at their present levels, and that if we were successful in prosecuting these 7(a) cases, he would not decrease his sales to his industrials, but would continue them at their present level, and if this resulted in a drop in the pipeline pressure at our delivery points, that was just too bad.
>
> He reminded me that Illinois Power was out at the end of the line.
>
> Q. What was your response to this?
>
> A. * * * I told [the Chief Executive Officer] that I doubted if the Federal Power Commission would tolerate any such action and that this threat didn't particularly disturb me.
>
> He told me that if there was a pressure drop he would never restore it until the FPC made him do it.

It was in the light of this testimony and the provisions of Section 7(a) and the Commission's allocation authority that the Examiner stated in his prior decision:

> As the Chief Executive Officer of Mississippi has recognized, the utility customers have been and will undoubtedly continue "to nibble away at" Mississippi's capacity not now allocated to the utility customers * * *, which they may properly do under Section 7(a). There is, of course, no necessity for a continued nibbling away at such capacity if it is all allocated at one time so as to provide each of the utility customers their pro rata share. Obviously, what the Commission can do piecemeal it can accomplish in one action.

Comparative Needs

The Commission's order reopening the record (*supra*, pp. 768–769) refers to the initial record as being "inadequate to weigh comparative needs." It therefore desired "information concerning the present and estimated future requirements of all customers served by Mississippi, including those customers which presently are not parties to the proceedings." In paragraph (a) of its order the Commission directed that additional evidence be taken "on the issues of the relative need of the various utility customers of Mississippi for gas from pipeline capacity available to Mississippi."

As the Examiner has already determined (*supra*, pp. 762–765), the pipeline capacity available to Mississippi is represented by the capacity of its existing system plus the capacity of Mississippi Transmission's system to the extent that it has not already been contracted for by Laclede, Illinois Power and St. Charles; that Mississippi Transmission's capacity also is equally available to Mississippi's industrial customers and its utility customers; that for the industrial customers to purchase a firm supply from Mississippi Transmission would create no more hardship on the industrial customers than on the utility customers; and that the general public would be beneficiary of the allocation of Mississippi's lower cost capacity to the utility customers.

As the record shows, the contracts which Mississippi has with its industrials provide for a six-month termination and that delivery of gas is contingent upon

a prior claim to such gas by Mississippi's utility customers. Accordingly, Mississippi has no need for firm gas to serve its industrial customers if their needs are to be determined in accordance with the terms of the contracts. Furthermore, Mississippi has no need even for interruptible gas to serve such customers after any six-month period it selects because the contracts, by their terms, are cancellable on six months notice.

The Commission's staff sent each of Mississippi's resale and direct customers a questionnaire soliciting information regarding the present and future requirements of such customers. Staff's Exhibit No. 99 is the tabulation of responses of the customers of Mississippi, and is divided into two tables, the first showing the responses of the utility customers, and the second showing the responses of the industrial customers. The staff made no substantive analysis of the requirements reported by any of the customers, but merely recorded, in Exhibit No. 99, the figures submitted by the various customers. Moreover, no witness for any industrial customer of Mississippi appeared at the reopened hearing to testify in support of the information submitted in answer to the staff's questionnaire. In this connection it is to be remembered that only 13 of Mississippi's 48 industrial customers even intervened in this proceeding.

Counsel for Mississippi assert that the industrial customers' "need for gas was fully spelled out and corroborated in the prior record." [13] In this connection they ignore that the fact that the Commission considered the initial record "inadequate to weigh comparative needs." In the absence of testimony at the reopened hearing from responsible officials of the industrial customers, and the failure of any party to make a showing as to comparative needs in the light of the Commission's order reopening the record, the present record can only be regarded as still inadequate for determining comparative needs on the basis the Commission had in mind.

Based upon the information received in response to the questionnaires submitted to all of Mississippi's customers, the Commission Staff witness presented an example of allocating Mississippi's capacity now utilized in serving industrial loads. Under his method that capacity, with certain adjustments, was allocated to both industrial (24,993 Mcf) and utility (29,115 Mcf) customers. The 29,115 Mcf allocated to utility customers is to be compared with the 64,586 Mcf allocated to such customers in the Examiner's decision issued September 13, 1960. For reasons now to be stated, the Examiner does not agree with the premise upon which the Staff theory is founded or with the result achieved.

The Staff witness relied exclusively on estimated requirements for the oncoming heating season 1961–62 as a basis for his recommended allocation. His reason was that "the further into the future these estimates are made the more likelihood there is of error occurring as well as the possibility of changed circumstances." This approach is out of harmony with the long-established Commission procedure which utilizes, in both Sections 7(a) and 7(c) proceedings, second and third year requirements in addition to those for the first year. Use of requirements for three years would have produced results comparing favorably with the Examiner's own proration of capacity on the basis of present stated demands.

A major inequity in the selection by the Staff witness of 1961–62 as a basis for allocation is, as pointed out by counsel for Illinois Power, "that he thus

[13] Counsel for Mississippi stated that "If the prior record in this case is inadequate to determine comparative needs, the utilities and the Staff have added nothing to the record * * *." The same can be said of Mississippi and the industrials. Except for four of Missippi's smaller utility customers (*supra*, p. 777), witnesses appeared for Mississippi's utility customers and supported their requests for increases in stated demand.

allocates increased quantities of low cost Mississippi gas to those companies which have made no efforts to alleviate the difficulties caused by Mississippi's failure to expand, while penalizing those companies which have made such efforts. In order to protect their consumers, in view of Mississippi's failure to expand and in view of the protracted nature of these proceedings, Illinois Power and Laclede have spent large sums in developing natural gas storage and have contracted to purchase certain quantities of relatively high priced [Mississippi] Transmission gas. Had they not done so, [the Staff witness] would have allocated more low price Mississippi gas to Illinois Power and Laclede * * *. Such an approach will only tend to defeat the Commission policy of encouraging development of natural gas storage."

Moreover, the Staff's method ignores not only the fact that Mississippi's direct industrial customers are entitled, under their respective contracts with Mississippi, to no more than interruptible service, but also the fact that the evidence shows that the full amounts desired by the industrial customers of Mississippi may be purchased by them from Mississippi Transmission. This fact is made clear not only by the testimony of the President of Mississippi Transmission (*supra*, pp. 764–765) but also the testimony of the President of Mississippi who testified that there is no physical reason why Mississippi could not deliver to the industrial customers the quantities desired by them, for the account of Mississippi Transmission without causing difficulties on Mississippi's system.

The Staff's allocation method also overlooks the necessity for removing the reason for Mississippi's standstill from 1956 to 1960 hereinabove discussed (*supra*, p. 758). Removal of Mississippi's service destroying motive in this proceeding is a simple matter. It can be accomplished simply by allocating to the utility customers the capacity utilized by Mississippi in serving its interruptible industrial loads; prohibiting further unlawful construction of facilities; and by causing appropriate revisions to be made in its inequitable tariff provisions. In the Examiner's view, what is shown to be necessary in this proceeding to protect the public interest must be made possible. The Examiner's disposition of this case eliminates the cause that Mississippi had for creating Mississippi Transmission. If Mississippi elects to continue Mississippi Transmission as a separate corporation it will do so by imposing unnecessary corporate expenses upon the consumers in its service area. As the President of Mississippi testified:

> PRESIDING EXAMINER: As a matter of fact * * *, isn't there every reason to believe that if Mississippi * * * had constructed Mississippi Transmission Company's system the over-all cost of constructing and operating that system would have been less, and what I have in mind is that it's cheaper to operate one company than it is to operate two, isn't it?
>
> The WITNESS: Yes.
>
> PRESIDING EXAMINER: Well, is there any reason why if Mississippi * * * had constructed a line Trunkline * * * would not have been just as willing to sell the gas to Mississippi * * * as it was to sell it to Mississippi * * * Transmission?
>
> The WITNESS: None whatever so far as I know.

As has been explained, Mississippi Transmission was created for the purpose of executing a scheme devised by Mississippi to cause natural gas consumers in Mississippi's service area to pay higher rates than they would have paid had Mississippi caused its system to be further expanded, the intended end result being the preservation of the profitability of Mississippi's earnings from its industrial sales. This scheme is not outside the jurisdiction of the Commission to deal with. Whatever the limits of the Commission's power it may forbid any acts done in furtherance of a scheme that is regarded as contrary to the public interest, whether it can forbid the scheme or not.

Allocation of Mississippi's Capacity to Its Utility Customers

The evidence in this case makes it clear that the utility customers here seeking increases in their stated demand are entitled to and should have allocated to them that portion of Mississippi's capacity now utilized by it in serving interruptible industrial loads, except for 2,000 Mcf for pilot light service.

The utility customers served by Mississippi and their present stated demands are:

Customer	Present stated demands (Mcf)
Arkansas Louisiana Gas Company	9,500
City of Altheimer	350
City of Augusta	915
City of Chester	1,068
City of Hazen	456
City of Red Bud	[1] 640
Fort Smith Gas Corporation	2,700
Illinois Power	57,202
Laclede	330,000
MidSouth	26,140
Missouri Natural	24,000
PUC Crossett	2,000
St. Charles	2,360
Town of Des Arc	415
Union Electric Company	10,000
Dupo	675
Natural Gas Improvement District No. 2 of Ashley County, Arkansas	374
Total	468,795

[1] Paragraph (C) of the Commission's order issued May 18, 1961, in City of Red Bud, Illinois, Docket No. G-16504, 25 FPC 987, directs Mississippi to deliver to the City of Red Bud "a maximum daily volume of 430 Mcf during the first year of operation, such maximum volume to be increased to 640.9 Mcf per day during either the second or third year of operation."

The daily sales capacity of Mississippi's system has been determined to be 534,000 Mcf. Subtracting from this total capacity the present stated demands of the utility customers of 468,795 Mcf, and an additional 2,000 Mcf for pilot light service, leaves a balance of 63,205 Mcf to be allocated to the utility customers seeking increases in their stated demand.

Only 447,303 Mcf of the daily sales capacity of 534,000 Mcf is deliverable in the St. Louis area. The three utility customers in that area now have stated demands aggregating 389,562 Mcf and are seeking stated demand increases aggregating 141,870 Mcf for the next three heating seasons (121,000 Mcf for Laclede; 17,548 Mcf for Illinois Power; and 2,322 Mcf for St. Charles). South of the St. Louis area the utility customers are seeking total stated demand increases of 26,952 Mcf (1,313 Mcf for PUC Crossett; 6,869 Mcf for Midsouth; 10,900 Mcf for Missouri Natural; 6,793 Mcf for Union; 582 Mcf for Dupo; and 504 Mcf for Ashley County). In short, Mississippi's utility customers are seeking an aggregate increase of 168,822 Mcf in their stated demands as compared to the 63,205 Mcf presently available for allocation.

The Examiner, in his intial decision, allocated Mississippi's available capacity on a pro rata basis in acordance with stated demands of all utility customers in effect at the time. With the exception of St. Charles there appeared to be no basic disagreement among Mississippi's utility customers with the proposition that such method of capacity allocation produced equitable results. Since some of the utility customers of Mississippi are not now seeking increases in their stated demand, the 63,205 Mcf available for allocation will be allocated only to those utility customers which have shown or indicated a need for increases in their stated demand. The 63,205 Mcf, if allocated on a pro rata basis (based on

existing stated demands) would increase the stated demands of the utilities here requesting or indicating a need for additional gas as follows:

	Present stated demand (Mcf)	Percent	Increase in stated demand (Mcf)
Laclede	330,000	72.89	46,070
Illinois Power	57,202	12.64	7,989
St. Charles	2,360	.52	329
PUC Crossett	2,000	.44	278
MidSouth	26,140	5.77	3,647
Missouri Natural	24,000	5.30	3,350
Union	10,000	2.21	1,397
Dupo	675	.15	95
Ashley County	374	.08	50
Total	452,751	100.00	63,200

The Examiner will adjust the allowance for Laclede by 570 Mcf so as to increase St. Charles' allowance from 329 Mcf to 899 Mcf. Accordingly, effective upon the date the Examiner's order becomes the final order of the Commission, Laclede's stated demand will be increased from 330,000 Mcf per day to 375,500 Mcf. St. Charles' stated demand will, effective as of the same date, be increased by 628 Mcf, or from 2,360 Mcf to 2,988 Mcf per day, and will be further increased on November 1, 1962, from 2,988 Mcf to 3,259 Mcf. The stated demand of Illinois Power will be increased by 7,989 Mcf, or from 57,202 Mcf to 75,191 Mcf per day, effective November 1, 1963.

The other six utility customers (PUC Crossett, MidSouth, Missouri Natural, Union, Dupo and Ashley County) of Mississippi located south of the St. Louis area would receive a total of 8,817 Mcf on the above stated pro rata basis. However, since MidSouth recently received an increase in its stated demand of 3,350 Mcf per day, it appears equitable to reallocate the 8,817 Mcf on the following basis:

Customer	Increase granted (Mcf)
Union	1,900
Missouri Natural	4,000
Dupo	300
PUC Crossett	750
Ashley County	250
MidSouth	1,617
Total	8,817

As has been pointed out (*supra*, p. 777), the only evidence as to the requirements of Union, Dupo, PUC Crossett and Ashley County is to be found in their responses to the Staff questionnaire. Accordingly, following the precedent set by the Commission in *American Louisiana Pipe Line Co., et al., Docket No. G–2306, et al.*, 15 FPC 23, 34–35; *Michigan Consolidated Gas Co.* v. *Federal Power Commission*, 283 F. 2d 204, 212, the volumes allocated to Union, Dupo, PUC Crosset and Ashley County will be reserved for not more than six months, during which time they may apply pursuant to Section 7(a) of the Act for the increased quantities allocated to them herein. In the event they fail to file an application within this period of time they will forfeit the right to receive the natural gas as authorized and provided herein.

Missouri Natural, having intervened in this proceeding and having supported its request for an increase in its stated demand, will be granted the relief it seeks in this proceeding (*Texas Eastern Transmission Corp., et al., Docket Nos. G–1003, et al.*, 8 FPC 139, 145–147).

Tariff Revisions

In the Examiner's decision issued September 13, 1960, it was shown that three revisions in Mississippi's existing tariff are necessary and desirable in the public interest. First, a revision to Section 11(b), First Revised Sheet No. 16, to provide that any buyer whose gas requirements have not been met by Mississippi will remain a general service buyer under the F–1 Rate Schedule if it obtains gas elsewhere. Second, a revision of the F–1 Rate Schedule, or the addition of a new Tariff Sheet, to provide for the sale of E or excess gas to Mississippi's utility customers which may be available to Mississippi's system from time to time, such excess gas to be sold to the utility customers in proportion to their effective stated demands. As stated in the Examiner's initial decision "Mississippi's present tariff discriminates against the utility customers in that it permits Mississippi to sell all of its excess capacity to its industrial customers, a practice which is inconsistent with the Act and the requirements of the Commission as to other pipelines." Third, a revision to Section 6 of Rate Schedule F–1 to provide a reduction in penalty charges for overruns, and to enable the utility customers, particularly Laclede and Illinois Power, to more nearly take their full stated demands. As the Examiner has pointed out in his prior decision, "Laclede, for example, has been unable to come within some 6,000 Mcf of taking its full stated demand (330,000 Mcf) on most days of the heating season because of the existing tariff penalty provisions. Mississippi agrees that the tolerance provision of its tariff works unfairly to deprive at least some of the utilities of the full stated demands. It does not, however, agree with other proposed revisions and additions to its tariff."

In its order reopening the proceedings herein, the Commission set forth, as one purpose of reopening, taking additional evidence on changes required in Mississippi's tariff pertaining to the establishment of priorities of service between direct and resale customers (*supra*, p. 769).

Concerning the penalty charges for overruns contained in Mississippi's existing tariff, the Examiner in his prior decision stated:

> Mississippi's FPC Gas Tariff permitted authorized overruns of only 1 percent of the stated demands or 1,000 Mcf, whichever is the greater, and even within that narrow limit there is a penalty provision with respect thereto. That is to say, if a utility customer does not overrun its stated demand more than five days in any one month or two days in succession, the penalty is $0.15 per Mcf. Otherwise, the penalty is $2.00 per Mcf. For all gas over the 1 percent (or 1,000 Mcf) limitation, the penalty is $10.00. As counsel for Laclede state, "Although in theory the utilities may be able to take excess gas to meet emergency demands, in actuality they cannot in most instances afford to pay the $10.00 per Mcf penalty rate, which is imposed regardless of the availability of the gas on" Mississippi's system. They further point out the "Because of the size of Laclede's take from its eight delivery points, any overrun would almost inevitably exceed the 1,000 Mcf 'first step' of $2.00 gas and go into the $10.00 penalty gas step in MRF"s existing tariff. An overrun of only 5% of Laclede's stated demand would result in a penalty of approximately $157,000 a day!"

> * * * During the 1958–1959 heating season Laclede was able to come within 3,000 Mcf of its stated demand on only three days. It took less than 325,000 Mcf on all but 19 days.

At the reopened hearing a Commission staff witness recommended a revision on Mississippi's tariff relating to payment for volumes taken in excess of stated demand which differed from that decided by the Examiner in his prior decision.[14]

Counsel for Mississippi state that Mississippi "relaxed the tolerance provisions of its tariff in respect of overruns in a filing made effective March 1, 1960, and is willing to further relax those provisions to the extent set forth in Exhibit 109; however, this is the most that Mississippi believes can properly be required." [15]

Staff counsel also recommended that interruptible service be made available on the basis of 50 percent to utility customers and 50 percent to direct industrial customers of Mississippi. The Examiner's prior decision ordered, subject to Commission review, that Mississippi make any excess gas available on its system from time to time to F–1 customers in proportion to their effective stated demands.

Evidence offered by Mississippi through two witnesses at the reopened hearing was directed at the claimed difficulties in administration and unworkability of the staff's tariff proposals, not at the Examiner's prior decision. Staff counsel, in his brief, appears to make no serious effort to support the tariff revisions proposed by his witness. The Examiner finds that the solutions provided in the Examiner's decision issued September 13, 1960, relating to overrun penalties and the making available overrun gas are the correct ones. These tariff revisions are necessary to avoid undue discrimination against Mississippi's utility customers and undue preference in favor of direct industrial customers. As the Examiner held in his prior decision—

> To be just and reasonable within the meaning of the Act a tariff applicable to a pipeline's utility customers must satisfy at least two broad principles. First, it must produce fair results between the supplier and its customers. Second, it must not unduly discriminate against any customer or class of customers. Mississippi's existing tariff does not satisfy the latter principle. That discrimination of the type now permitted by that tariff is prohibited by Section 4(b) of the Act is a question to which the Court addressed itself in *Panhandle Eastern Pipe Line Co.* v. *F.P.C.*, 232 F. 2d 467, *cert.* den., 352 U.S. 891, and decided adversely to Mississippi's contention* * *.

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[14] The revision proposed by the staff witness would provide a penalty of 5.88 cents per Mcf for any excess taken over stated demand up to the first 2 percent or 100 Mcf, whichever is greater; of $2.00 per Mcf for any volume over 2 percent of 100 Mcf, whichever is greater but not over 3 percent or 100 Mcf, whichever is greater; and $5.00 per Mcf for volumes over 3 percent or 100 Mcf, whichever is greater. These penalties would apply only on days on which Mississippi sells no interruptible gas. On days on which Mississippi sells any interruptible industrial gas, any excess over stated demand taken by a resale customer would be deemed interruptible gas, not subject to overrun penalty.

[15] Paragraph 6(b) of Exhibit No. 109, relating to payment for volumes exceeding stated demand, provides:

(b) If the volume of such excess gas taken by Buyer exceeds the Stated Demand by not more than 100 Mcf or 2% of the Stated Demand, whichever is greater, and such excess volume is taken in any billing month for not more than 2 consecutive days or on not more than 5 days, Buyer shall pay for such excess volume of gas at the rate of 15¢ per Mcf in lieu of the rate provided in paragraph (a) above in addition to the commodity charge otherwise applicable. Otherwise, the provisions of paragraph (a) above shall apply as to payment for all volumes taken by Buyer in excess of the Stated Demand. In determining whether such excess volumes have been delivered for not more than 2 consecutive days or not more than 5 days during any billing month, no consideration shall be given to any day on which the volume of excess gas is less than 1% of Buyer's Stated Demand or 50 Mcf, whichever is larger.

In the *Panhandle* case (13 FPC 301) referred to the Commission was faced with a situation somewhat similar to that faced here with reference to Mississippi's position. Panhandle sought to establish priorities of service for some of its direct sale customers. Alleging that its interruptible rate schedules were inequitable and unworkable, Panhandle proposed to cancel them—claiming that they afforded advantages to industrial customers of the utilities not available to Panhandle's own direct industrial customers and that cancellation was necessary to protect the pipeline's firm deliveries and to control interruptible deliveries to certain customers of its utilities. The Commission, in denying the request to cancel, rejected every argument advanced by Panhandle in favor of according preferential treatment either to direct industrial customers as a group or individually. With particular reference to the contention that the industrial customers of Panhandle's resale customers might receive preferential treatment over the pipeline's own firm customers, the Commission said (13 FPC at pp. 307–308):

> Another claim by Panhandle is that the "I" Schedules are inequitable in that discrimination would develop against Panhandle's direct customers in favor of the latter's competitors served by Panhandle's distributors in the event that the "I" schedules are implemented. In our opinion Panhandle's apprehensions are not well founded. Testimony in the record indicates it is more likely that absence of an interruptible rate schedule would result in discrimination against customers of Panhandle's resale customers in favor of Panhandle's direct customers. Accordingly, Panhandle's contentions in this regard are not persuasive. Moreover, it should be pointed out that the interruptible schedules, as modified, broaden Panhandle's opportunities to render service to direct customers.

It is apparent that Mississippi, in opposing revisions in its existing tariff, is doing so primarily to protect its earnings from industrial sales to the detriment of the public interest. In this connection, and as stated in *Alabama Power Co.* v. *F.P.C.*, 128 F. 2d 280, 296, *cert.* den., 317 U.S. 652, with respect to licensees under the Federal Power Act, which has equal applicability here:

> * * * the Commission has many duties to perform, over a long period of time, other than coaxing a reluctant licensee to act as the law requires that it shall act.

The findings and order accompanying the Examiner's decision issued September 16, 1960, are modified and expanded to the extent hereinafter set forth.

FINDINGS

(1) Mississippi, having its principal place of business at St. Louis, Missouri, owns and operates a natural gas transmission pipeline system located in the States of Texas, Louisiana, Arkansas, Missouri and Illinois, and by such operations Mississippi is engaged in the transportation and sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission, and is, therefore, a natural-gas company within the meaning of the Act as found by the Commission in its order of March 1, 1944, Docket No. G–291, 4 FPC 535.

(2) Laclede, Illinois Power, MidSouth, St. Charles, Union, Missouri Natural, PUC Crossett, Dupo and Ashley County, each is a person engaged in the local distribution of natural gas to the public and each purchases natural gas from Mississippi for resale for ultimate public consumption under the terms and provisions of Mississippi's FPC Gas Tariff, Original Volume No. 1.

(3) MidSouth, Illinois Power and St. Charles each have filed an application under Section 7(a) of the Act; Laclede, Union and Missouri Natural have each

filed intervening petitions in said 7(a) applications; and Laclede has filed a complaint upon which the Commission has instituted an investigation. Each of these proceedings is directed against Mississippi and seeks an increase in the stated demand of each which is now in effect in Mississippi's FPC Gas Tariff, Original Volume No. 1, 10th Revised Sheet No. 25, and seeks certain revisions of the terms and provisions of Mississippi's said FPC Gas Tariff, Original Volume No. 1.

(4) Responses filed by PUC Crossett, Dupo and Ashley County to the Commission staff questionnaire indicate their need for increases in their stated demands for the 1961–62, 1962–63, and 1963–64 heating seasons.

(5) The sustained dependable delivery capacity of Mississippi's system for future stated demand purposes is not less than 534,000 Mcf, of which not less than 447,303 Mcf is deliverable in the St. Louis area.

(6) Increasing the stated demands of each of Mississippi's utility customers, to the extent and in the manner provided in paragraph (A) and (B) below, will not place an undue burden upon Mississippi and will not impair its ability to render adequate service to its customers.

(7) Mississippi shall continue to sell and to deliver natural gas to each of its utility customers, such sale and delivery to be henceforth on the basis of the stated demands set forth in paragraphs (A) and (B) below.

(8) It is necessary and desirable in the public interest that Mississippi make the following changes in or additions to its FPC Gas Tariff Original Volume No. 1:

(a) A revision of Section 11(b), First Revised Sheet No. 16, to provide that any buyer whose gas requirements have not been met by Mississippi will remain a general service buyer under the F–1 Rate Schedule if it obtains gas elsewhere.

(b) A revision of F–1 Rate Schedule, or the addition of a new Tariff Sheet, to provide for the sale of E or excess gas which may be available on Mississippi's system from time to time, such excess gas to be sold to the F–1 customers in proportion to their then effective stated demands. Excess gas rejected by any F–1 Rate Schedule buyer will be apportioned equitably among the remaining F–1 buyers desiring to purchase such excess.

(c) A revision to Section 6 of Rate Schedule F–1 which will provide that for each day that a buyer exceeds its stated demand by not more than 2 percent or 1000 Mcf, whichever is greater, the charge for such excess take per Mcf shall be the commodity charge of the rate schedule increased by 1/30 of the demand charge under the rate schedule; for excess takes above the stated demand by more than 2 percent but not more than 3 percent, or 1000 Mcf, whichever is greater, a penalty charge of $2.00 per Mcf shall apply in addition to the commodity charge under the rate schedule; and for takes in excess of 3 percent of the stated demand or 1000 Mcf, whichever is greater, a penalty charge of $5.00 per Mcf of excess shall apply in addition to the commodity charge under the rate schedule.

(9) It is necessary and desirable in the public interest that Mississippi be required to file applications for certificates of public convenience and necessity for authority to continue to serve such direct sales customers as it was not serving on the effective date of its "Grandfather" certificate.

(10) It is necessary and desirable in the public interest that Mississippi be required to file an application for a certificate of public convenience and necessity for authority to continue the operation of all facilities comprising its system for which it has not heretofore made application and received certificate authority to construct and operate.

(11) Mississippi and its responsible officers and directors have willfully and knowingly failed to comply with the certificate provisions of the Act and the Commission's rules pertaining thereto.

(12) It is appropriate for the Commission to transmit to the Attorney General of the United States a copy of the record in this proceeding, together with a request that criminal proceedings be instituted, under the provisions of Sections 20 and 21 of the Act, against Mississippi and its officers and directors.

(13) It is appropriate for the Commission to require Mississippi to enter into service agreements with Arkansas Louisiana Gas Company, Cities of Augusta, Chester, Hazen and Red Bud, Illinois Power, PUC Crossett, St. Charles, Town of Des Arc, Union, Dupo, and Ashley County.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission:

(A) Mississippi be, and it is hereby directed, to increase the stated demands of Laclede, St. Charles, MidSouth and Missouri Natural, effective upon the date this order becomes the final order of the Commission, as follows:

Customer	Present stated demands (Mcf)	Increase granted (Mcf)	Total stated demands (Mcf)
Laclede	330,000	45,500	375,500
St. Charles	2,360	628	2,988
MidSouth	26,140	1,617	27,757
Missouri Natural	24,000	4,000	28,000

(B) Mississippi be, and it is hereby directed, to further increase the stated demand of St. Charles, effective November 1, 1962, by 271 Mcf, or from 2,988 Mcf to 3,259 Mcf, and to also increase the stated demand of Illinois Power, effective November 1, 1963, by 7,989 Mcf, or from 57,202 Mcf to 65,191 Mcf.

(C) Of Mississippi's existing capacity available for allocation to its utility customers, there is reserved until further order of the Commission, 1,900 Mcf for Union, 300 Mcf for Dupo, 750 Mcf for PUC Crossett, and 250 Mcf for Ashley County, which have indicated in responses to a Commission staff questionnaire that they are in need of increases in their stated demands. Each of these utility customers of Mississippi shall make application within six months—from the date this order becomes the final order of the Commission—for the increased quantities indicated. Upon failure of these utility customers to make application pursuant to Section 7(a) of the Act for these increased quantities within said six-month period, or failure to support such application, such quantities will be distributed pro-rata among the parties hereto up to their demonstrated requirements. Hearings concerning such 7(a) applications shall be limited to the issue of applicant's requirements, all other issues having been determined herein.

(D) Mississippi be, and it is hereby directed, to file, in a form acceptable to the Commission, the changes in or additions to its FPC Gas Tariff Original Volume No. 1 set forth in paragraph (8) above.

(E) Mississippi be, and it is hereby directed to file an application or applications for certificates of public convenience and necessity for authority to continue to serve such direct sales customers as it was not serving on the effective date of its "Grandfather" certificate.

(F) Mississippi be, and it is hereby directed, to file an application or applications for certificates of public convenience and necessity for authority to continue the operation of all facilities comprising its system for which it has not heretofore made application and received certificate authority to construct and operate.

(G) Mississippi be, and it is hereby directed, to enter into service agreements on or before July 1, 1962, with Arkansas Louisiana Gas Company, Cities of Augusta, Chester, Hazen and Red Bud, Illinois Power, PUC Crossett, St. Charles, Town of Des Arc, Union, Dupo, and Ashley County, and to file said service agreements with the Commission.

(H) The record in this consolidated proceeding be referred to the Attorney General of the United States with a request that criminal proceedings be instituted against Mississippi and its officers and directors, under Sections 20 and 21 of the Act, for violation of the certificate provisions of the Act and the Commission's rules pertaining thereto.

(I) The filings to be made by Mississippi pursuant to paragraphs (A), (B), (D), (E) and (F) above shall be made within 60 days from the date this order becomes the final order of the Commission.

FRANCIS L. HALL,
Presiding Examiner

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

EL PASO NATURAL GAS COMPANY, DOCKET NO. G–12580

ORDER AMENDING ORDERS ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued April 18, 1962)

On October 11, 1961, El Paso Natural Gas Company (Petitioner) filed a petition to amend the Commission's orders issued March 26, 1958, and November 27, 1959, in Docket No. G–12580, 19 FPC 681 and 22 FPC 900, respectively.

The order of March 26, 1958, issued a certificate of public convenience and necessity to Petitioner authorizing, among other things, a 2,500 horsepower compressor unit to be installed at Petitioner's Goldsmith Compressor Station, Ector County, Texas. After receiving authorization, Petitioner found that it had available in stock a 2,000 horsepower compressor unit which, rather than continuing to stock for an indefinite period of time, it installed in place of the 2,500 horsepower compressor unit. Although the smaller unit will not produce the capacity originally proposed, Petitioner states that it will not impair its ability to perform the service certificated in Docket No. G–12580. Therefore, Petitioner requests that the subject order be amended to authorize the 2,000 horsepower compressor unit in lieu of the 2,500 unit.

The order of November 27, 1959, issued a certificate of public convenience and necessity to Petitioner authorizing, among other facilities, a 16-inch O.D. meter run and appurtenances to be located at Topock, Arizona, where Petitioner had proposed to deliver gas to Southern California Edison Company (Edison). The subject meter run was to be used for separate measurement of the gas to be sold directly to Edison. However, the subject order did not permit Petitioner to deliver gas directly to Edison, but instead required that such gas be sold to Southern California Gas Company and Southern Counties Gas Company of

California. The order of November 27, 1959, did not elminate authorization for the subject 16-inch O.D. meter run, and, accordingly, Petitioner requests amendment of the order so as to eliminate such authorization.

The Commission finds:

It is necessary and appropriate to carry out the provisions of the Natural Gas Act, and the public convenience and necessity require that the Commission's orders issued March 26, 1958, and November 27, 1959, in Docket No. G–12580, as amended, be further amended as hereinafter ordered.

The Commission orders:

(A) The Commission's order issued March 26, 1958, in Docket No. G–12580, as amended, is hereby further amended so as to authorize Petitioner to install a 2,000 horsepower compressor unit at its Goldsmith Compressor Station, Ector County, Texas, in lieu of the presently authorized 2,500 horsepower compressor unit.

(B) The Commission's order issued November 27, 1959, in Docket No. G–12580, as amended, is hereby further amended so as to eliminate the authorization in said order for a 16-inch O.D. meter run and appurtenances to have been installed near Topock, Arizona.

(C) In all other respects, said orders shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

THE WASHINGTON WATER POWER COMPANY, PROJECT NOS. 204, 2058, AND 2075

ORDER WAIVING PENALTIES FOR DELINQUENCY IN PAYMENT OF ANNUAL CHARGES

(Issued April 18, 1962)

On February 2, 1962, statements of the annual charges for the calendar year ended December 31, 1961, under the licenses for Project Nos. 204, 2058, and 2075, respectively, were mailed to The Washington Water Power Company, licensee for the projects. The letter of transmittal stated that the charges should be paid within 30 days of rendition of the bills therefor.

In transmitting its check covering the annual charges owing, which was not received until March 9, 1962, the licensee explained that the delay was due to the sudden hospitalization of the executive exercising control over such payments and the fact that our statements were overlooked during his absence.

Our records relating the past payment of annual charges by the licensee for the projects involved show consistent promptness in payment.

The Commission finds:

It will not be inconsistent with the public interest to waive the penalties owing by reason of the licensee's delay in payment of the annual charges.

The Commission orders:

The penalties arising out of the delay of The Washington Water Power Company, licensee for Project Nos. 204, 2058, and 2075, respectively, in the payment of the annual charges under the licenses for the projects for the calendar year ended December 31, 1961, is waived.

AMERICAN LOUISIANA PIPE LINE COMPANY, DOCKET NO. CP61–24; TIDEWATER OIL COMPANY, DOCKET NO. CI61–125; PAN AMERICAN PETROLEUM CORPORATION, DOCKET NO. CI61–164; SOCONY MOBIL OIL COMPANY, INC., DOCKET NO. CI61–254; HUMBLE OIL & REFINING CO., DOCKET NO. CI61–307; UNION PRODUCING COMPANY, DOCKET NO. CI61–318; J. RAY McDERMOTT & CO., INC., DOCKET NO. CI61–1240

ORDER MODIFYING AND ADOPTING DECISION OF PRESIDING EXAMINER AND DENYING INTERVENTION

(Issued April 19, 1962)*

Syllabus

1. Statement of General Policy is not in and of itself controlling in case of initial prices proposed under pre-Policy statement contracts, at least when service has been theretofore initiated. [here deliveries have not started] P. 793.
2. Commission notes Examiner's discussion of appropriate price "line" for area in terms of comparison with other sales and his official notice of other area prices as reflected by past orders, and on basis of these matters specifically *finds* a base price of 17¢ per Mcf, exclusive of tax reimbursements, is in line for proposed northern Louisiana sales. P. 793.
3. Commission *issues* certificates of public convenience and necessity to American-Louisiana and producer applicants, under Section 7 of the Natural Gas Act. P. 793; 799.

Charles V. Shannon, for American Louisiana Pipe Line Company.

Jack D. Jones for Tidewater Oil Company.

John F. Jones, *William H. Emerson*, *Norton Standeven*, and *William J. Grove* for Pan American Petroleum Corporation.

Roy L. Merrill for Socony Mobil Oil Company, Inc.

William J. Merrill and *George H. Lawrence* for Humble Oil & Refining Company.

Wilbert O. Crain, *Saunders Gregg*, *Vernon W. Woods*, and *C. Huffman Lewis* for Union Producing Company.

T. P. Hull, Jr., for J. Ray McDermott & Co., Inc.

Kent H. Brown, *Martin L. Barr*, *Charles J. Cox*, and *Barbara M. Suchow* for Public Service Commission of the State of New York.

James O'Malley, Jr., *Halcyon G. Skinner*, *John A. Lodge*, and *Eugene B. Thomas, Jr.*, *for Consolidated* Edison Company of New York, Inc.

David J. Bardin for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

The Presiding Examiner issued an initial decision in these proceedings on March 12, 1962. The Examiner would grant certificates of public convenience and necessity to the applicants herein, conditioning the independent producers' certificates upon reduction of the proposed initial price. Three parties to these proceedings, the Public Service Commission of the State of New York (PSC), Pan American Petroleum Corporation, and Humble Oil & Refining Corporation, filed exceptions to the decision on April 2, 1962.

PSC says the Examiner erroneously based his decision entirely and exclusively on the Commission's Statement of General Policy No. 61–1 (issued September 28,

* Initial decision appears on p. 793.

1960, 24 FPC 818) even though the initial prices here at issue are based on contracts executed prior to the issuance of our Policy Statement. While we do not fully agree with PSC's characterization of the Examiner's decision, we do agree that the Statement of General Policy is not in and of itself controlling in the case of initial prices proposed under pre-Policy Statement contracts at least when service had been therefore initiated. PSC is correct in citing our previous holdings to that effect.

The Examiner's decision discusses the appropriate price "line" for this area in terms of comparison with other sales. The Examiner properly took official notice of other prices in the area as reflected by this Commission's certificate orders. On the basis of these matters we specifically find that a base price, exclusive of tax reimbursement, not in excess of 17¢ per Mcf is in line for the sales here proposed. See, also, our order of March 21, 1962, in *The Ohio Oil Company*, Docket No. G–15385, *et al.*, 27 FPC 551.

Pan American excepted to some, but not all, of the matters noticed by the Examiner. But Pan American has not sought leave to adduce additional evidence controverting the facts so noticed. Additional lengthy exceptions filed by Pan American (and adopted by Humble) are without merit; they should be and are denied.

While the record does not so show, we take notice that J. Ray McDermott & Co., Inc., is now a "natural-gas company" and modify the Examiner's finding paragraph (1) accordingly.

Consolidated Edison Company of New York, Inc., filed a petition to intervene in these proceedings on March 22, 1961. Consolidated Edison's only asserted interest in these proceedings is the possibility that we might modify the area prices announced in our General Policy Statement. Since we hold that Statement not to govern these applications Consolidated Edison's petition should be denied.

The Commission orders:

(A) The decision of the Presiding Examiner issued March 12, 1962, herein, as hereinabove modified, is adopted as the Commission's decision and order in these proceedings.

(B) The petition to intervene filed by Consolidated Edison is denied.

DECISION

UPON APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued March 12, 1962)

PURDUE, *Presiding Examiner:* These consolidated proceedings concern the following applications for certificates of convenience and necessity under Section 7(c) of the Natural Gas Act:

(1) An application of American Louisiana Pipe Line Co. (Docket No. CP61–24) (which owns and operates an interstate natural-gas pipeline system) for authorization to construct and operate an 8-inch supply lateral extending from its existing 30-inch main line in Franklin Parish, Louisiana, approximately 25 miles to the Holly Ridge Field, in Tensas Parish, Louisiana. The field is located in northern Louisiana, near the easterly border of the state, and nearly one-third of the distance between the northerly and southerly borders.

(2) Applications of six independent producers, Tidewater Oil Co. (Docket No. CI61–125), Pan American Petroleum Corp. (Docket No. CI61–164), Socony Mobil Oil Co., Inc. (Docket No. CI61–254), Humble Oil & Refining Co. (Docket No. CI61–307), Union Producing Co. (Docket No. CI61–318), and J. Ray McDermott & Co., Inc. (Docket No. CI61–1240), for authorization to sell to Amer-

ican Louisiana natural gas produced in the Holly Ridge Field. The sales are to be made pursuant to gas purchase contracts entered into in May, June and July of 1960, and cover proved recoverable reserves of 29,930 Mcf (at 14.73 psia). Average daily takes are to be sufficient to deplete 91% of the committed reserves in 20 years, and American Louisiana may take between 75% and 125% of that average on any one day. The producers are to make delivery of the gas to American Louisiana in the Holly Ridge Field. The gas is to be delivered at sufficient pressure (but not in excess of 1050 pounds) to allow the gas to enter American Louisiana's lateral. The initial base price specified in each of the six gas purchase contracts is 18.25¢ per Mcf (at 15.025 psia). In each of the contracts, American Louisiana agrees to reimburse the producer for 75% of 2.0¢ of the severance tax presently imposed.

The proceeding came on for hearing before the Examiner on April 10, 11, 12, and 13, 1961, and September 6, 1961. Evidence both oral and documentary was introduced by the applicants; and documentary evidence, by the Commission Staff. Cross-examination of witnesses was conducted by the Staff.

Prior to the commencement of the hearing, the Public Service Commission of the State of New York filed a notice of intervention in the proceedings; and Consolidated Edison Co. of New York, Inc., a petition to intervene. Thereafter, most of the applicants filed "answers," "objections," "protests" or "motions to dismiss" whereby they requested that said state commission and company be denied leave to intervene. This Commission has not yet taken action in the premises. The Examiner permitted the State commission and company tentatively to participate in the hearing, and accorded them an opportunity to file briefs, subject to the granting by this Commission of leave to intervene, and with the qualification that if such leave be denied, the participation of the New York Commission and Consolidated Edison should go for naught.

On April 24, 1961, following the conclusion of the applicant's cases-in-chief, the Staff made a motion to dismiss the six independent producer proceedings. At the request of the Staff, the Examiner referred the motion to the Commission for determination. Thereafter, the Staff filed a brief in support of its motion, and all of the applicants except J. Ray McDermott & Co., Inc., filed briefs in opposition thereto. On May 24, 1961, the Commission directed that the motion to dismiss be referred to the Examiner for disposition in the instant decision.

On September 6, 1961, the proceedings were submitted for consideration and decision by the Examiner upon the evidence presented, the briefs filed with the Commission respecting the motion to dismiss, and a statement which the New York Public Service Commission made at the hearing respecting its position.

Applicants introduced evidence at the hearing in the attempt to show that the Commission should issue certificates to the six independent producers authorizing the sales at 18.25¢ per Mcf (at 15.025 psia), despite the Commission's Statement of General Policy No. 61–1 (F.P.C. *Rules of Practice and Procedure*, Sec. 2.56), which fixes a rate guidance standard of 17.0¢ per Mcf (at 15.025 psia) as the initial service rate for independent producer sales made in what the Commission has prescribed as the Northern Louisiana Area.

The New York Public Service Commission argues that the record is inadequate to justify unconditional certification of the sales; and that if the sales are authorized at all, the certificates should be so conditioned as to permit an initial price no higher than 15.5¢ per Mcf.

The Commission Staff hold to their position that the motion to dismiss should be granted. What the staff position is should the motion be denied, is not clear.

MOTION TO DISMISS

The Staff, in their motion to dismiss, aver,

> that an applicant who (1) proposes an out-of-line initial price, (2) is unable to adduce evidence sufficient in law to call for an exercise of Commission discretion as to the propriety of such price, and (3) has not commenced service under temporary authority, must himself "seek a certificate appropriately conditioned,"

This position is without merit. The producer applicants are entitled to undertake to establish that they should have a price higher than the guideline rate for the Northern Louisiana Area specified in Policy Statement No. 61–1. The Policy Statement declares as follows:

> * * * in the absence of compelling evidence calling for other action by us, proposed initial sales of natural gas by independent producers which include rates higher than those indicated in the appendix attached to this statement [which specifies 17.0¢ per Mcf (at 15.025 psia) for the Northern Louisiana Area] shall be denied a certificate or certificated only upon the condition that lower rates be filed, * * *

Applicants in good faith attempted to make a showing that a price higher than 17.0¢ is justified.

The motion to dismiss is denied.

CONSIDERATION OF MERITS OF APPLICATIONS

Applicants have failed to produce "compelling" evidence, or any persuasive evidence, that the producer sales should be authorized without the certificates being conditioned upon the sales being made at the area price level for northern Louisiana prescribed in Policy Statement No. 61–1. Accordingly, the certificates hereinafter issued to the six independent producers will be so conditioned.

As the Examiner interprets the briefs which have been filed, only applicants American Louisiana, Pan American and Tidewater now object to the price condition being imposed.

The arguments which these three applicants advance in the attempt to justify a higher price than 17.0¢ will be briefly adverted to. Said three applicants make a protest against Policy Statement No. 61–1; and in effect claim that the Commission's prescribing that all of northern Louisiana should be a separate area, and its prescribing a guide rate of 17.0¢ for all of such area, are not justified. In contradistinction to the 17.0¢ per Mcf (at 15.025 psia) for the Northern Louisiana Area (which embraces the Holly Ridge Field), the Policy Statement specifies a guideline rate of 21.25¢ per Mcf (at 15.025 psia) for southern Louisiana, which is designated the Southern Louisiana Area; and a guideline rate of 21.5¢ (at 15.025 psia) for Mississippi, which is designated the Mississippi Area.

American Louisiana introduced evidence that in the Southern Louisiana Area, it has been purchasing gas at 18.25¢ and 20.0¢ per Mcf for several years. It claims that the Holly Ridge Field is in the same or an analogous gas production area, and therefore that the 18.25¢ price for the Holly Ridge gas is warranted. Pan American argues similarly that the price of 18.25¢ for the sales made in the Holly Ridge Field is justified by the prices which producers charge in south Louisiana and Mississippi.

These attacks upon the establishment of all of northern Louisiana as a separate area, and the 17.0¢ per Mcf rate standard in such area, are specious; and fall before the considerations which led the Commission to adopt the various areas and price levels set out in Policy Statement No. 61–1.

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In the Policy Statement, the Commission declared as follows:

> * * * The geographical areas which we have used are convenient and well known. * * *
>
> In arriving at the price levels for the various areas * * *, we have considered all of the relevant facts available to us. Such consideration included cost information from all decided and pending cases, existing and historical price structures, volumes of production, trends in production, price trends in the various areas over a number of years, trends in exploration and development, trends in demands, and the available markets for the gas.

And in *Panhandle Eastern Pipe Line Co.*, Opinion No. 350, 27 FPC 35 at 42, the Commission said:

> It would defeat our purpose of simplifying and clarifying producer regulation, if every individual proceeding were to become a forum for attacking the area standards and we were to begin varying those standards from case to case.

The promulgation of Policy Statement No. 61–1 was within the Commission's authority. *Wisconsin* v. *Federal Power Commission* (App. D.C.), decided Nov. 30, 1961, slip opin. pp. 7–8, 15–19. Two Courts of Appeals have expressed their approval of the Commission's action in issuing the Policy Statement. *J. M. Huber Corp.* v. *Federal Power Commission* (C.A. 3), 294 F. 2d 568, 570; *Sohio Petroleum Co. v. Federal Power Commission* (C.A. 10), decided Dec. 19, 1961, slip opin. p. 3.

American Louisiana, Pan American and Tidewater point to evidence that there are two certificated sales in the Northern Louisiana Area at prices higher that 17.0¢ (at 15.025 psia). One of these sales is to Gulf Oil Corp. at a price of 18.5¢; the other is to The California Co. from the Lake St. John Field in Tensas Parish at a price of 21.5¢. Said applicants also note that there are two intrastate sales in the Northern Louisiana Area at 18¢ and 19¢, respectively.

These sales do not militate against the soundness of the guideline rate for the Northern Louisiana Area being fixed at 17.0¢. Deliveries under The California Co. sales will not commence until in or about 1965. See *South Georgia Natural Gas Co*, 22 F.P.C. 211, 220. If in settling upon the area guide rate which it prescribed the Commission gave but little consideration to The California Co. sale and to the two intrastate sales, its method was in accord with judicial precedent. "* * * the 'line' referred to in Catco may properly be referenced to relevant existing producer prices under which substantial amounts of natural gas move in interstate commerce." *United Gas Improvement Co.* v. *Federal Power Commission* (C.A. 9), 283 F. 2d 817, 823. According to the evidence which applicants adduced, the sale to Gulf Oil Corp. is the only sale in the Northern Louisiana Area at a price in excess of 17.0¢ where the gas now moves in interstate commerce.

In contrast to this single sale, the Commission, in the period of one and one-half years immediately prior to the adoption of Policy Statement No. 61–1 on September 28, 1960, issued permanent certificates for sales in number and at base prices as follows in what is now the Northern Louisiana Area: one sale at 16.0¢ per Mcf; thirteen sales at 16.5¢ per Mcf; and two sales at 17.0¢ per Mcf (all at 15.025 psia).[1]

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[1] Sale at 16.0¢ per Mcf: *Austin E. Stewart*, Docket No. G–17802 (certificate issued July 9, 1959). Sales at 16.5¢ per Mcf: *Mobley & Stephens*, Docket No. G–16562 (certificate issued June 19, 1959); *Pan American Petroleum Corp.*, Docket No. G–16465 (certificate

As the Commission said in *Panhandle Eastern Pipe Line Co., supra*, at page 44, concerning the "'Other' Oklahoma area," so here: "This pattern of presently certificated sales in the area establishes the line for the proposed sales and shows a reasonable relationship between the Policy Statement area ceiling and existing sales." Obviously, to the extent that the guide rate of 17.0¢ was based upon the pattern of existing prices in the area, such rate is justified.

American Louisiana introduced evidence that since 1953 it has followed a consistent policy of paying an initial price of 18.25¢ per Mcf for gas delivered in the fields to which it has to construct laterals. This circumstance is immaterial. The Commission's Policy Statement No. 61–1 takes precedence over American Louisiana's policy.

American Louisiana, Tidewater and Humble note that the Holly Ridge Field is situated some 130 to 150 miles closer to American Louisiana's markets than the gas located farther down its line, in southern Louisiana, where the price indicated by Policy Statement No. 61–1 for initial service is 21.5¢ per Mcf; and argue that, ergo, a price of at least 18.25¢ for the Holly Ridge gas is warranted. This argument is not convincing. Assuming for the purpose of the discussion that distance from market is an element which should enter into a determination of a proper initial price, such element is more than offset by other considerations of which the Examiner takes notice as matters of specialized knowledge. These are the following: northern Louisiana has a history of lower prices than southern Louisiana; sales in southern Louisiana started later than in northern Louisiana; competition for gas is stronger in southern Louisiana; drilling costs in southern Louisiana are higher; there are differences between northern and southern Louisiana gas fields in geological characteristics; and in southern Louisiana there are some off-shore production problems.

Lastly, Pan American correctly states that the 18.25¢ per Mcf price is not higher than American Louisiana's weighted average cost of purchased gas. In a similar vein, American Louisiana, Socony, Tidewater, Humble and Union correctly represent that the price proposed in the instant producer contracts (18.25¢ plus 1.5¢ tax reimbursement) is less than the weighted average cost of 19.29¢ exclusive of tax reimbursement for American Louisiana's gas purchased from producers. These circumstances are immaterial.

It is a justifiable inference from the record that the proposed sales of natural gas in question, either at 17.0¢ per Mcf or at 18.25¢ per Mcf, would not result in a triggering of general price rises in the area involved.

The position taken by the New York Public Service Commission that the sales should only be certificated at a price no higher than 15.5¢ per Mcf, is contrary to Policy Statement No. 61–1, and cannot prevail.

The evidence shows that there is a market for the gas which is the subject matter of the contracts here involved; that the six producers have the ability to

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issued September 28, 1959); *Southwest Gas Production Co., Inc., et al.*, Docket No. G–16764 (certificate issued September 28, 1959); *Southwest Gas Production Co., Inc., et al.*, Docket No. G–17404 (certificate issued December 22, 1959); *Atlantic Refining Co.*, Docket No. G–15541 (certificate issued March 18, 1960); *W. C. Feasel, et al.*, Docket No. G–16922 (certificate issued May 5, 1960); *Pan American Petroleum Corp.*, Docket No. G–17877 (certificate issued May 5, 1960); *Hunt Oil Co.*, Docket No. G–18029 (certificate issued May 5, 1960); *Humble Oil & Refining Co.*, Docket No. G–18289 (certificate issued May 5, 1960); *Phillips Petroleum Co.*, Docket No. G–18300 (certificate issued May 5, 1960); *Socony Mobil Oil Co., Inc.*, Docket No. G–17955 (certificate issued July 14, 1960); *Bodcow Co.*, Docket No. G–18781 (certificate issued July 14, 1960); *H. L. Hunt et al.*, Docket No. G–20490 (certificate issued October 31, 1960). Sales at 17.0¢ per Mcf: *T. L. James & Co., Inc.*, Docket No. G–19407 (certificate issued July 14, 1960); *M. B. Rudman, et al.*, Docket No. G–19466 (certificate issued September 20, 1960).

furnish such gas; that upon the construction of the proposed supply lateral of American Louisiana, its facilities will be adequate to take the gas; that the reasonably-estimated cost of the supply lateral is $840,000; that such lateral is economically feasible; that American Louisiana will defray such cost from funds on hand; and that construction of the proposed lateral, in addition to enabling American Louisiana to purchase gas in the Holly Ridge Field, will give said pipeline company access to additional existing and potential gas reserves in the general area of such field.

FINDINGS AND CONCLUSIONS

Upon consideration of the evidence adduced and the briefs of counsel, it is further found and concluded that:

(1) Applicants American Louisiana Pipe Line Co., Tidewater Oil Co., Pan American Petroleum Corp., Socony Mobil Oil Co., Inc., Humble Oil & Refining Co., and Union Producing Co., are each a "natural-gas company" within the purview of the Natural Gas Act; and upon the commencement of the sale by applicant J. Ray McDermott & Co., Inc., hereinafter authorized, said last named applicant will become a "natural-gas company" within the purview of such Act.

(2) The sales of natural gas, hereinbefore described, by Tidewater Oil Co., Pan American Petroleum Corp., Socony Mobile Oil Co., Inc., Humble Oil & Refining Co., Union Producing Co., and J. Ray McDermott & Co., Inc., to American Louisiana Pipe Line Co. (more fully described in the application) will be made in interstate commerce, subject to the jurisdiction of the Commission; and such sales, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) The facilities hereinbefore described involved in Docket No. CP61-24 (more fully described in the application in such proceeding), which American Louisiana proposes to construct and operate, are to be used for the transportation and sale of natural gas in interstate commerce for resale, subject to the jurisdiction of the Commission, as an integral part of American Louisiana's existing natural-gas pipeline system; and the construction and operation of such facilities are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The facilities referred to in Finding and Conclusion (3) are adequate to render the service which American Louisiana proposes and which said applicant is hereinafter authorized to provide.

(5) American Louisiana, Tidewater, Pan American, Socony, Humble, Union, and J. Ray McDermott are each able and willing properly to do the acts and to perform the service proposed by them, respectively, in the proceedings Docket Nos. CP61-24, CI61-125, CI61-164, CI61-254, CI61-307, CI61-318 and CI61-1240; and to conform to the provisions of the Natural Gas Act, and the requirements, rules and regulations of the Commission thereunder.

(6) The sales of natural gas by Tidewater, Pan American, Socony, Humble, Union, and J. Ray McDermott for which said applicants seek authorization, and the construction and operation for which American Louisiana seeks authorization, are required by the public convenience and necessity; and certificates therefor should be issued as hereinafter ordered and conditioned.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal, or review by the Commission on its own motion, as provided in its Rules of Practice and Procedure, that:

(A) Certificates of public convenience and necessity be and the same are hereby issued, in Docket Nos. CI61–125, CI61–164, CI61–254, CI61–307, CI61–318, and CI61–1240, upon the terms and conditions of this order to Tidewater Oil Co., Pan American Petroleum Corp., Socony Mobil Oil Co., Inc., Humble Oil & Refining Co., Union Producing Co., and J. Ray McDermott & Co., Inc., authorizing the sales by them to American Louisiana Pipe Line Co. involved in such proceedings, hereinbefore described and more particularly described in their applications, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor.

(B) A certificate of public convenience and necessity be and the same is hereby issued, in Docket No. CP61–24, upon the terms and conditions of this order, to American Louisiana Pipe Line Co., authorizing said applicant to construct and operate the facilities involved in such proceeding, hereinbefore described and more particularly described in its application, for the transportation and sale of natural gas as therein set forth.

(C) As a condition attached to each of the certificates issued to the producer applicants in paragraph (A) hereof, and to the exercise of the rights thereunder, the initial price for the sales by the respective producers shall be 17.0¢ per Mcf (at 15.025 psia), exclusive of tax reimbursement.

(D) The certificates issued in paragraphs (A) and (B) hereof shall be deemed to be accepted and in full force and effect, unless refused in writing and under oath within 30 days from the issuance of this order; and the facilities authorized by said certificates shall be constructed and placed in actual operation within six months from the issuance of this order.

(E) The general terms and conditions set forth in paragraph (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act shall attach to the issuance of the certificates referred to in paragraph (A) hereof, and to the exercise of the rights granted hereunder; and the general terms and conditions set forth in paragraph (c)(1), (c)(3), (c)(4), and (e) of such section 157.20 shall attach to the issuance of the certificate referred to in paragraph (B) hereof, and to the exercise of the rights granted hereunder.

(F) The grant of the certificates herein shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act, or of Part 154 of the Commission's Regulations under the Natural Gas Act, requiring the filing of rate schedules for the service herein authorized; and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceedings now pending or hereafter instituted against the applicants. Further, the action taken in these proceedings shall not foreclose or prejudice any future proceedings or objection concerning any price for the gas sold under, or related provision in, the gas purchase contracts here involved.

HOWELL PURDUE,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

COLUMBIA GULF TRANSMISSION COMPANY, DOCKET NO. G–19376

FINDINGS AND ORDER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued April 19, 1962)

On January 12, 1962, Columbia Gulf Transmission Company (Applicant) filed in Docket No. G–19376 an application in compliance with Paragraph (D) of the

Commission's order issued December 28, 1959, in said docket, for authority to acquire and operate an experimental compressor unit on a permanent basis, all as more fully set forth in the application.

In the order of December 28, 1959, Applicant received authority to construct and operate an additional 10,500 horsepower compressor engine unit, consisting of a gas turbine with modified aircraft jet engine driving a centrifugal compressor, at its existing compressor station No. 2 near Clementsville, Kentucky, for experimental purposes to test the feasibility of using this new type of compressor unit. If Applicant decided to acquire and operate the unit on a permanent basis, it was required by said order to file an application for authorization to acquire and operate the facility on a permanent basis at least 60 days prior to the end of the test period.

Accordingly, Applicant has filed the subject application and states that the experimental unit has proven to be a success and that it intends to use the facility for standby operations until sometime in the future when it will be used in connection with a system capacity increase.

The predicted construction cost of the subject facility was $1,554,000. The actual cost will be $1,647,200 due to a required increase in the size of the main building to accommodate the equipment.

Due notice of the filing of the subject application and opportunity for hearing has been given by publication in the Federal Register on March 23, 1962 (27 FR 2749).

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act, and the public convenience and necessity require that the Commission's order of December 28, 1959, in Docket No. G–19376 (22 FPC 1149) be amended as hereinafter ordered.

The Commission orders:

(A) The Commission's order of December 28, 1959, in Docket No. G–19376 (22 FPC 1149) be and the same is hereby amended to authorize Applicant, Columbia Gulf Transmission Company, to acquire and operate the compressor unit hereinbefore described, as more fully described in the application in this proceeding, as a permanent installation for standby purposes unless authorized for other purposes in subsequent orders of the Commission.

(B) In all other respects the Commission's order of December 28, 1959, in Docket No. G–19376 (22 FPC 1149) shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

EL PASO NATURAL GAS COMPANY, DOCKET NO. G–2206

ORDER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND PERMITTING WITHDRAWAL OF PETITIONS

(Issued April 19, 1962)

On October 6, 1961, El Paso Natural Gas Company (El Paso) filed a motion to withdraw petitions and a petition to amend the Commission's order, as amended, issued September 18, 1953, in Docket No. G–2206, 12 FPC 1234. The subject order authorized El Paso to construct and operate ten meter stations to serve natural gas to The Navajo Tribe (Tribe) for distribution in Window Rock, Hunters Point, St. Michaels, Ganado, Greasewood, and Leupp, all in Arizona, and Shiprock, Toadlena, Tohatchi, and Twin Lakes, all in New Mexico.

On October 11, 1954, El Paso filed a petition for an extension of time in which to commence construction of the foregoing facilities. On March 23, 1959, El Paso filed a petition to further amend the order of September 18, 1953, so as to delete the facilities necessary for service to Toadlena, Tohatchi, and Twin Lakes, New Mexico, and Hunters Point, Ganado, Greasewood, and Leupp, Arizona. Said petition also requested an extension of time to commence construction of facilities for service to St. Michaels and Window Rock, and further requested permission to withdraw the petition filed October 11, 1954. Facilities for natural gas service to Shiprock had been completed and placed in actual operation.

The subject motion and petition filed October 6, 1961, requests permission to withdraw El Paso's petitions filed October 11, 1954, and March 23, 1959, and, further, said motion and petition requests the Commission to amend the order issued September 18, 1953, so as to delete therefrom authorization for the facilities necessary for service to Toadlena, Tohatchi, and Twin Lakes, New Mexico, and Window Rock, Hunters Point, St. Michaels, Ganado, Greasewood, and Leupp, Arizona.

El Paso states that natural gas service for three new areas, to be rendered pursuant to a budget-type certificate authorization issued in another proceeding, together with continued service for the Shiprock area will satisfy the Tribe's present requirements for natural gas. The Tribe consents to the subject proposed deletion of authorization of facilities.

The Commission finds:

(1) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act, and the public convenience and necessity require that the Commission's order issued September 18, 1953, in Docket No. G–2206, as amended, be further amended as hereinafter ordered.

(2) The motion to withdraw El Paso's petitions to amend filed on October 11, 1954, and March 23, 1959, in Docket No. G–2206, appears to be in the public interest and should be granted as hereinafter ordered.

The Commission orders:

(A) The Commission's order issued September 18, 1953, in Docket No. G–2206, as amended, is hereby further amended by deleting therefrom authorization for the construction of facilities necessary to serve Toadlena, Tohatchi, and Twin Lakes, all in New Mexico, and Window Rock, Hunters Point, St. Michaels, Ganado, Greasewood, and Leupp, all in Arizona.

(B) The motion to withdraw El Paso's petitions to amend filed on October 11, 1954, and March 23, 1959, in Docket No. G–2206, is hereby granted.

(C) In all other respects, said order issued September 18, 1953, shall remain in full force and effect.

UNION ELECTRIC COMPANY, DOCKET NO. E–6927

OPINION AND ORDER UPON A DECLARATION OF INTENTION

(Issued April 19, 1962)*

Syllabus

1. Commission *holds* that the non-navigable East Fork of the navigable Black River is a stream over which Congress has jurisdiction under the Commerce Clause. P. 806.

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* Designated Commission's Opinion No. 356; initial decision appears on p. 809. Rehearing denied by order issued June 20, 1962, 27 FPC 1366. Set aside, *Union Electric Company* v. *F.P.C.*, 326 F. 2d 535 (CA8–1964); cert. granted on October 12, 1964.

2. Rejecting view that "the interests of interstate commerce" in Section 23(b) [of the FPA] are limited to "effect upon navigable capacity", Commission *holds* [for the first time] that the development of power for interstate transmission and use is such an effect upon the interests of interstate commerce within the meaning of Sec. 23(b) that a project proposed for that purpose, which is to be constructed in and will utilize non-navigable waters over which Congress has jurisdiction under commerce clause, *must be licensed.* P. 808.
3. Instant proposal found sufficient evidence of East Fork's potential to affect interstate commerce to cause requirement of license, even if it were not shown that downstream navigable capacity will be affected—however Commission concurs in conclusion that it has license jurisdiction because of effect on downstream navigation. P. 808.
4. Commission *requires* Union Electric to obtain license for its proposed Taum Sauk project, pursuant to provisions of Federal Power Act. P. 809.

Duane Allen Patterson for Union Electric Company

Joseph B. Hobbs for the Staff of the Federal Power Commission

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

Ross, *Commissioner*

The Commission is presented with the question whether or not a license is required under Part I of the Federal Power Act for the construction of a pumped storage, hydroelectric generating project upon a non-navigable tributary of an interstate navigable stream. The Union Electric Company (Union) proposes to build such a project, known as the Taum Sauk project, to develop 350,000 kw of peaking power for its interstate system by damming the East Fork of the Black River at its confluence with Taum Sauk Creek in Reynolds County, Missouri.

The project consists of a man-made upper pool on top of a mountain, at 1,515 to 1,625 ft. above sea level, capable of holding 4,350 acre feet of water. The upper pool is connected with two 175,000 kw generating-pumping turbines at 750 ft. elevation by a 6,400 ft. pressure tunnel and conduit. An open, tail water channel connects this plant with the adjoining lower pool which is created by a 60-foot high dam across the East Fork.

The dam spillway is at 750 ft. above sea level. It is planned to maintain the water level at 734 ft., there being 4,350 acre feet capacity between 734 and 750. During the project's eight-hour maximum 350,000 kw generating cycle, water from the upper pool at an average rate of 6,800 cfs will enter the lower pool. During the 11-hour pumping cycle, which requires an average of 392,000 kw, between 3,750 and 4,900 cfs will be pumped into the upper pool.

At 715 ft.—on the dam—there will be sluice gates capable of discharging 2,000 to 2,800 cfs, depending on the level of water behind the dam, into the natural stream bed of the East Fork. It is contemplated that, after the initial impounding of water, all of the natural flow into the lower pool will be released through the sluice gates. Because of the varying inflow and constantly changing head of impounded water above the gates, the sluices would require continual adjustment to permit the natural flow and only the natural flow to pass. But, absent mechanical or human failure or a change in the operation, it would be possible to so control the flow except in periods of high water.

The East Fork is a flashy, non-navigable stream with recorded flows from less than one cf to over 33,000 cfs, its estimated average flow at the proposed dam site being 105 cfs. The Black River is navigable from its confluence with the East Fork, four miles below the proposed dam site, and flows interstate, joining the White River in Arkansas.

All the basic facts in the record concerning the proposed project and its effect upon water resources related to it were stipulated. From the facts, as stipulated, the examiner found that the East Fork of the Black River is a non-navigable stream over which Congress has jurisdiction under the commerce clause. He found further that the project, under contemplated normal operation, would have an inevitable effect upon the navigability of the Black River during periods of extreme flows and that it created a capability to affect radically the navigable capacity of the Black River at any time. For these reasons he ruled that the project had to be licensed, citing *Citizens Utilities Co.* v. *F.P.C.*, 279 F. 2d 1 (1960), and *Carolina Aluminum Co.*, 19 FPC 704 (1958).

Section 23(b) of Part I of the Federal Power Act which concerns the licensing of projects on non-navigable streams reads in pertinent part as follows:

> * * * Any person, association, corporation, State, or municipality intending to construct a dam or other project works across, along, over, or in any stream or part thereof, *other than those defined herein as navigable waters, and over which Congress has jurisdiction under its authority to regulate commerce* with foreign nations and among the several States shall before construction file declaration of such intention with the Commission, whereupon the Commission shall cause immediate investigation of such proposed construction to be made, and *if upon investigation it shall find that the interests of interstate or foreign commerce would be affected by such proposed construction* such person, association, corporation, State or municipality shall not construct, maintain, or operate such dam or other project works until it shall have applied for and shall have received a license under the provisions of this Act. If the Commission shall not so find, and if no public lands or reservations are affected, permission is hereby granted to construct such dam or other project works in such stream upon compliance with State laws. [41 Stat. 1075, 49 Stat. 846; 16 U.S.C. 817] [Emphasis supplied.]

This subsection deals exclusively with projects to be located on non-navigable streams. A license is required for such a project only if the Commission finds (1) that Congress has jurisdiction over the non-navigable stream under its commerce powers and (2) that the proposed construction will affect the interests of interstate or foreign commerce. We will take these points up in order.

The Jurisdiction of Congress Over the Stream

We reach the question of whether or not the construction of the Taum Sauk project affects the interests of interstate commerce only if we first determine that Congress has jurisdiction over the East Fork of the Black River. The scope of Congress' jurisdiction over the water resources of the nation has been a matter of continuing controversy since the turn of the last century. We think it important, therefore, first to determine the scope of that jurisdiction under the commerce clause; in the light of the history of the Federal Power Act of 1920.

Before the turn of this century, private interests began to recognize the advantages to be derived from harnessing the nation's water power to produce large amounts of inexpensive electric energy. Since most of the best dam sites to accomplish this purpose were either on navigable waters, on public lands or on forest lands of the United States, an Act of Congress was required in order to develop the power. More and more bills were introduced in Congress to permit unhampered, private development of the nation's water resources, until in 1908, the conservationists, led by President Theodore Roosevelt, announced that they would attempt to block all such legislation that resulted in a free grant in perpetuity of the nation's water resources to private interests. The long and

often bitter fight which ensued resulted in the passage in 1920 of the Federal Water Power Act, now Part I of the Federal Power Act.

The jurisdiction of Congress over navigable waters was well established prior to 1900 as an incident of its commerce powers, although there was dispute for some years over what constituted "navigation." *United States* v. *Appalachian Power Co.*, 311 U.S. 377 (1940), reversing 107 F. 2d 769 (4th Cir., 1939); *Wisconsin Public Service Corp.* v. *F.P.C.*, 147 F. 2d 743 (7th Cir., 1945), *certiorari* denied, 325 U.S. 880.

The private interests attempting to secure favorable water power legislation insisted that Congress' sole jurisdiction over water resources was over those waters actually used for navigation. The conservationists, however, felt that a river system, navigable in part, was a unit from its forest headwaters to its mouth and that Congress had jurisdiction over the whole. In order to justify such broad jurisdiction in the Federal government under the law and attitudes then existing, the conservationists pointed out that navigation on the lower reaches of a river system could not be protected and developed unless Congress had jurisdiction over the upper portion to control floods, low water, hydraulic mining, soil erosion and stream pollution. Based on this reasoning, they felt it within the power of Congress to control the development of the whole river system in the national interest to insure its maximum development for all beneficial public purposes, including domestic and municipal water supply, agricultural and industrial use, the development of power and recreation as well as navigation.

The conservationists received support for their broad concept of jurisdiction when the United States Supreme Court ruled that under the Rivers and Harbors Act of 1890, 26 Stat. 454, Congress had jurisdiction under the commerce clause to prevent construction in a non-navigable river which affected the navigable capacity of downstream waters. *United States* v. *Rio Grande Dam and Irrigation Co.*, 174 U.S. 690 (1899). Using the rationale of the Supreme Court in that case, the Special Congressional National Waterways Commission, in its final report in 1912, concluded that the authority of Congress reaches to the sources of every stream (page 46). On this basis, the Waterways Commission further declared that Congress might withhold its permit for construction in or over streams, either navigable or non-navigable, or might grant its permit with conditions (pages 47, 48). The Commission stated:

> * * * With the increasing unity of our national life and the growing necessity of securing for human needs the maximum beneficial use of the waters of every stream it will become increasingly necessary to treat every stream with all its tributaries as a unit. In the nature of the case so comprehensive a policy could be successfully administered only by the Federal Government, and consequently the eventual desirability of Federal control is easy to predict (p. 52).

The legislative history of the Federal Water Power Act demonstrates the struggle between the two principal competing forces, the one desirous of using the power potential of the nation's water resources with as little restriction as possible and, therefore, attempting to limit the scope of Congress' exercise of jurisdiction over streams; the other struggling to preserve all possible water resources for their most beneficial use by present and future generations and, therefore, attempting to exercise Congress' jurisdiction to the full.

The definition of navigable waters in the House amendment to Senate Bill 1419, 65th Congress, 2d session, 1918, was broad enough to include the waters of a river system from its mouth to its source, thereby including the non-navigable tributaries of navigable waters. It provided:

> "Navigable waters" means all streams or parts of streams, and other bodies of water or parts thereof, over which Congress has jurisdiction under its authority to regulate commerce with foreign nations and among the several states.

The committee of conference, however, working under tremendous pressure in the 3d session of the 65th Congress, proposed the following definition:

> That the term "navigable waters" as used in this Act and as applied to streams shall be construed to include only such streams or parts of streams as are in their ordinary natural condition used for the transportation of persons or property in interstate or foreign commerce, or which through improvement heretofore or hereafter made have been or shall become usable in such commerce.

The new definition was limited to streams navigable in fact, and indeed, excluded the shoals and falls which held the major water power potential. This fact made the definition unacceptable to the conservationists and resulted in the La Follette filibuster in the closing hours of the session on March 4, 1919, which postponed any water power legislation until the next Congress.

The 66th Congress, by compromise, achieved the final definition, which is as follows:

> "Navigable waters" means those parts of streams or other bodies of water over which Congress has jurisdiction under its authority to regulate commerce with foreign nations and among the several states, and which either in their natural or improved condition notwithstanding interruptions between the navigable parts of such streams or waters by falls, shallows, or rapids compelling land carriage, are used or suitable for use for the transportation of persons or property in interstate or foreign commerce, including therein all such interrupting falls, shallows, or rapids, together with such other parts of streams as shall have been authorized by Congress for improvement by the United States or shall have been recommended to Congress for such improvement after investigation under its authority.

It is most significant, however, that when the definition of "navigable waters" was changed by the conference committee of the 65th Congress to exclude non-navigable tributaries, new language *specifically* dealing with the licensing of projects in waters *not* navigable under that definition was added to Section 23 of the proposed Act, which theretofore had dealt exclusively with pre-existing rights. That new language was amended to its final form in Section 23(b), as set forth above, and clearly manifests Congressional intent to claim its jurisdiction over non-navigable waters as well as waters navigable under the definition. The viewpoint of the conservationists thus prevail. As it pertains to this case, the question then becomes: Is the non-navigable East Fork of the navigable Black River a stream over which Congress has jurisdiction under the commerce clause?

The East Fork is one of three tributaries which join to form the Black River. Some of the waters of each of the three tributaries originate in the Clark National Forest which lies approximately seven air miles to the north and 5½ miles to the west of the proposed dam site of the Taum Sauk project. Fourteen and one-half stream miles south of the proposed dam site is the head of the existing Clearwater Dam flood control pool on the Black River.

The Clark National Forest was authorized by the National Forest Reservation Commission on August 30, 1933, under the provisions of the Act of March 1, 1911 (36 Stat. 961), which authorizes and directs the Secretary of Agriculture to locate and recommend for purchase forest land within the watersheds of navigable streams as in his judgment may be necessary to the regulation of the flow of

navigable streams or for the production of timber. The Clearwater Flood Control Dam was authorized by Act of June 25, 1938 (52 Stat. 1215), "for the benefit of navigation and the control of destructive floodwaters and other purposes."

Congress has, then, already exercised its commerce powers over water resources in connection with the river system whose source is upstream from the proposed project and which extends interstate to where it joins first the White River and then the Mississippi River in Arkansas and eventually empties into the Gulf of Mexico. The East Fork of the Black River is but a small part of this river system, but one over which we hold Congress has jurisdiction under the commerce clause.

The Effect of the Project Upon Interstate Commerce

Having established that Congress has jurisdiction over the stream, we must now determine whether the construction of the proposed project will affect the interests of interstate or foreign commerce. In the past the Commission has limited its investigations in this regard to a determination of whether a proposed project is capable of affecting the navigable capacity of any downstream navigable waters. The presiding examiner in this case similarly limited his decision.

On the basis of the facts stipulated, he found that construction of the proposed project would have an inevitable effect upon the navigable capacity of the Black River during periods of high water; and further that the project would have the capability of substantially affecting that navigability at all times.

Staff counsel urged the presiding examiner to find that the interests of interstate commerce would be affected in another regard. It had been stipulated that the proposed project would use the waters of the East Fork to develop 350,000 kilowatts of peaking power for transmission and utilization in interstate commerce. Staff counsel urged that this effect upon the interests of interstate commerce was sufficient, by itself, to require a license for the Taum Sauk project.

The examiner stated that he felt it unnecessary to decide the issue thus presented because of his findings concerning effect upon navigable capacity. Although he did not base his decision thereon, he did make the following finding of fact:

> The proposed Taum Sauk Project will be constructed. operated and maintained for the development of power to supply markets not only in Missouri but also in the State of Illinois, thereby affecting the interests of interstate or foreign commerce.

A similar argument was advanced by staff and rejected by the Circuit Court in *United States* v. *Appalachian Power Co.*, 107 F. 2d 769 (4th Cir., 1938), at the same time that that court endorsed a narrow concept of navigability. The Circuit Court was reversed on this latter ground by the United States Supreme Court at 311 U.S. 377 (1940) in a way which made it unnecessary to decide issues presented only in connection with non-navigable streams. This is the first time that the Commission itself has decided the issue, whether an effect on the interests of interstate commerce other than an effect on navigable capacity is sufficient to require the licensing of projects on non-navigable waters under the mandate of Section 23(b).[1] Although it may be technically unnecessary to the decision in this case, an issue of such importance must not be allowed to go unresolved any longer since there can be little doubt that this country in the

[1] In *California Oregon Power Company*, 13 FPC 1, 3, the Commission disagreed with the presiding examiner but did not state the basis for disagreement.

years ahead will become overwhelmingly more dependent upon the maximum development of its water resources in all their uses.

When in 1919, as discussed *supra*, specific provisions concerning the licensing of projects on non-navigable waters were first added to Section 23, they provided in part:

> * * * if the contemplated improvement is, in the judgment of the commission, desirable and justified in the public interest for the purpose of improving or developing a waterway or waterways *for the use or benefit of navigation in interstate or foreign commerce*, the applicant may receive a license under the conditions with all of the rights and privileges herein provided for streams or parts of streams used for the transportation of persons or property in interstate or foreign commerce in their ordinary, natural, or improved condition. [Emphasis supplied.]

These provisions failed of passage, together with the extremely narrow definition of navigable waters, as a result of the La Follette filibuster previously mentioned. When the next Congress passed the Water Power Act, most significantly all direct reference to navigation was removed from the above language and, instead, it was provided that the Commission shall require a license for a project on a non-navigable stream

> * * * if upon investigation it shall find that the interests of interstate or foreign commerce would be affected by such proposed construction * * *.

Union urges that the term "interests of interstate or foreign commerce" is limited in meaning under Section 23 to "navigable capacity of downstream navigable waters," and that these terms are synonomous as far as the purposes of the Federal Water Power Act are concerned. It points out that this was, in effect, the holding of the Circuit Court in the *Appalachian* case. In light of the explicit change wrought by the amendment to Section 23 noted above and our interpretation of the purposes of the Federal Water Power Act, we cannot agree with Union's contention.

In *First Iowa Coop.* v. *F.P.C.*, 328 U.S. 152 (1946), the United States Supreme Court recognized the Federal Water Power Act as "the outgrowth of a widely supported effort of the conservationists to secure enactment of a complete scheme of national regulation which would promote the comprehensive development of the water resources of the nation * * *" (p. 180). It stated further: "That it was the intention of Congress to secure a comprehensive development of national resources and not merely to prevent obstructions to navigation is apparent from the provisions of the Act" (pp. 180–1).

Contrary to the often suggested thesis that the 1920 Federal Water Power Act was concerned solely with promoting the use of water resources for the single purpose of power development while at the same time protecting navigation, the legislative history and the language of the Act, itself, indicate the broader intent to preserve the nation's water resources not only for power and navigational purposes, but for their most beneficial use, whatever its nature, in the present and the future. The conservationists reasoned that Congress could and should condition the use of the water resources over which it had jurisdiction in connection with its duty to protect and develop commerce to insure comprehensive development and use of these national resources for all "beneficial public uses," such as domestic and municipal supply, agriculture, industry and recreation. They noted that measures for the control of water for the purposes of power and navigation, such as reforestation and control of hydraulic mining, stream pollution and soil erosion, could also benefit these other public uses. Because of the essential nature of the resources, they did not wish it forever

committed to the single use of power development, and so they insisted on recapture provisions, to insure that if it is necessary in the public interest to emphasize a different use of a particular water resource in the future, this may be done upon a financial basis which is fair to all.

An example of the foresightedness of the early conservationists is to be found in a matter currently pending before the Commission. Plans are under consideration for a multi-purpose project for flood control, irrigation, recreation and 150,000 kw. power development which will inundate a single purpose 24,300 kw project licensed in 1929. The recapture provisions applicable to the early license, which was for a period of less than 50 years, may affect the economics of the proposed project if it is finally authorized.

If there had been any question concerning the broad purposes of the 1920 Act, they were removed by the amendments of 1935. At that time, for instance, all references to "navigation" were removed from Section 7 of the Act and reference to the development of "water resources for public purposes" was added. The Act in its present form clearly reflects the intent to permit the most comprehensive, multiple purpose development[2] of the water resources of the nation which is presently proposed, subject, however, to recapture by the people, at the end of the license period. The Act gives the Federal Power Commission the authority to refuse to license a project that does not make the most comprehensive and best use of the water resources of the region involved. The constitutional power of Congress to so condition the use of water resources under its jurisdiction was upheld by the Supreme Court in the *Appalachian* case, *supra*, at page 399, when it stated:

> In our view, it cannot properly be said that the constitutional power of the United States over its waters is limited to control for navigation. By navigation respondent means no more than operation of boats and improvement of the waterway itself. In truth the authority of the United States is the regulation of commerce on its waters. Navigability, in the sense just stated, is but a part of this whole. * * * That authority is as broad as the needs of commerce.

In view of these facts, we cannot hold, as requested by Union that "the interests of interstate commerce" in Section 23(b) are limited to "effect upon navigable capacity." On the contrary, we hold that the development of power for interstate transmission and use is such an effect upon the interests of interstate commerce within the meaning of Section 23(b) that a project proposed for that purpose, which is to be constructed in and will utilize non-navigable waters over which Congress has jurisdiction under the commerce clause, must be licensed.[3] If the water resource is one over which Congress has jurisdiction and if the water resource has the potential of affecting interstate commerce in any manner, it is our duty to license its use to preserve the rights of the people in the resource. In this case, the proposed development of power for interstate transmission and use is sufficient evidence of the East Fork's potential to affect interstate commerce to cause us to require a license, even if it were not shown that downstream navigable capacity will be affected. We concur, however, in the conclusion of the Examiner that the Commission has license jurisdiction because of effect on downstream navigable capacity.

History has proved the conservationists of the first years of this century correct and attests to the wisdom of the provisions of the Federal Power Act which preserved the nation's water resources for their most comprehensive and

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[2] "including recreational purposes," (Section 10 as amended in 1935).

[3] The Commission's authority to issue a license for the proposed project on this basis is expressly set forth in Section 4(e).

beneficial use in the future while, at the same time, permitting their most comprehensive present proposed use. In a message to Congress on March 1, 1962, the President of the United States stated:

> Our nation's progress is reflected in the history of our great river systems. The water that courses through our rivers and streams holds the key to full national development. Uncontrolled, it wipes out homes, lives, and dreams, brings disaster in the form of floods; controlled, it is an effective artery of transportation, a boon to industrial development, a source of beauty and recreation, and the means for turning arid areas into rich and versatile cropland. In no resource field are conservation principles more applicable. By 1980, it is estimated, our national water needs will nearly double—by the end of the century, they will triple. But the quantity of water which nature supplies will remain almost constant.

The role of the Federal Power Commission in the control and preservation of our national water resources, when their use is proposed for power purposes, is to insure the most comprehensive and best use of those resources for the benefit of all of the people of the nation.

We adopt all of the findings of fact and decision of the presiding examiner as modified and supplemented by this decision.

The Commission orders:

(A) The request for oral argument is hereby denied.

(B) Union Electric Company is required to obtain a license for its proposed Taum Sauk Project works, pursuant to the provisions of the Federal Power Act.

DECISION

UPON A DECLARATION OF INTENTION

(Issued December 19, 1961)

BINDER, *Presiding Examiner:* This proceeding requires a determination whether a license is required under the Federal Power Act (Act) to construct, operate, and maintain a pumped-storage hydroelectric project known as the Taum Sauk Project to be located on the East Fork of the Black River at its confluence with Taum Sauk Creek, in Reynolds County, Missouri.

Union Electric Company (Union or Declarant) which proposes to construct, operate, and maintain such project contends that the Federal Power Commission (Commission or FPC) has no jurisdiction in the matter, that the granting of an FPC license is not required, and that the Taum Sauk Project may be constructed, operated and maintained upon compliance with State laws alone. In this connection Union filed a declaration of intention pursuant to Section 23(b) of the Act primarily for the purpose of obtaining an order holding that this Commission is without licensing jurisdiction in this matter. However, in view of the importance of the project to Union and its customers, Union filed with the Commission an application for a license authorizing the construction, operation, and maintenance of the project. The determination to be made in the licensing proceeding is not at issue here. This proceeding is limited to a determination whether the FPC has the power and authority to require a license authorizing the construction, operation and maintenance of the Taum Sauk Plant.

The project to be constructed will be a high-head pumped storage hydroelectric project. The proposed project works will consist of a concrete gravity dam approximately 60 feet high above its foundations and approximately 450 feet long, including 350 feet of overflow spillway with free crest at elevation 750

feet above mean sea level, U.S.G.S. datum, creating the "lower pool" with a total surface area of approximately 370 acres in the East Fork of the Black River and Taum Sauk Creek; the water impounded in the lower pool (consisting of approximately 6,000 acre-feet of which approximately 4,000 acre-feet would lie between elevations 735 and 750) being pumped against a dynamic head of approximately 811 feet into an energy storage reservoir designated the "upper pool"; the "upper pool," to be constructed on top of an adjoining mountain, to have a surface area of approximately 32 acres, and to impound approximately 4,000 acre-feet between elevations 1515 and 1625 within a rock-fill concrete-faced dike approximately 110 feet high; a 6,400-foot-long pressure tunnel and conduit, connecting the upper pool with a pumping and generating station on an open channel to the lower pool; two reversible units to pump water at night to the upper pool and to serve as generators during the day, each unit when generating to have a rated capacity of 175,000 kilowatts, two 138,000 volt transmission lines connecting the proposed installation with the Union Electric Company system.

The proposed project will be operated for the purpose of carrying peak loads on Declarant's system, for providing emergency generating capacity, and as otherwise appropriate to the operation of its system.

The facts with regard to the project works may be described generally as follows:

Initially, when the project plant is first employed in the generation of electric energy it is contemplated that the upper pool will have in storage up to a maximum of 4,350 acre-feet. The flow of water during generation of electricity from the upper pool to the lower pool will vary depending upon the amount of water contained in the upper pool. For example, when generating at a rate of 350,000 kilowatts, the rate of flow of water from the upper pool to the lower pool will vary depending on the amount of water in the upper pool. The lower the level of water in the upper pool the greater the rate of flow from the upper pool to the lower pool. For example, when the water in the upper pool is at a net head of 835 feet the flow from the upper pool to the lower pool is estimated to be at the rate of 5,800 cubic feet per second, and when the net head is 750 feet the rate of flow from the upper pool to the lower pool is estimated to be at 6,600 cubic feet per second.

It was also estimated that the average turbine discharge while generating would average as much as 6,800 cubic feet per second.

When the upper pool is filled there would be enough water stored to permit generation at the rate of 350,000 kilowatts to produce a total of approximately 2,750,000 kilowatt hours, corresponding to a full load operation of 350,000 kilowatts for about eight hours.

The operating cycle of the project works when pumping may be described as follows: When the project plant begins to pump water from the lower pool to the upper pool, the two units operating together at 200 revolutions per minute as a motor driven pump will deliver at approximately 4,900 cubic feet per second. Later when the upper pool is nearly filled, the rate of flow will decrease to about 3,750 cubic feet per second. It would take about 11 hours to fill the upper pool to 4,350 acre feet. The power absorbed by the motors varies from approximately 404,000 kilowatts when the upper reservoir is low to about 342,000 kilowatts when the reservoir is full, and at an average head about 392,000 kilowatts.

The dam for the lower pool will include an overflow spillway about 350 feet long with free crest at elevation 750 feet above mean sea level. The plans provide for a maximum water surface at the dam for the lower pool to be 763 feet above mean seal level, at which level the spillway would have a capacity to pass

a discharge of 70,000 cubic feet per second. An increase of one foot in the water surface at the spillway would result in a discharge capacity in the order of 80,000 cubic feet per second.

Union in the normal operation of the pool proposes to regulate the outflow through the dam when the water surface is at 750 feet above mean sea level, or less, by means of sluice gates capable of discharging from 2,000 to 2,800 cubic feet per second. Union intends to regulate the outflow through the dam to correspond to the inflow to the lower pool from the feeding streams by means of the sluice gates and appropriate gauging stations to record inflows and outflows. The sluice gates would control the flow through an outlet in the dam to be located on a center line at elevation 715 feet above mean sea level.

After Union filed its declaration of intention the Staff of the Commission made an investigation and concluded that the construction, operation, and maintenance of the proposed project would affect the interests of interstate and foreign commerce, *i.e.*, the Staff concluded that the licensing provisions of the Act were applicable.[1] Union requested a hearing and pursuant to Commission order such hearing was held on January 31, 1961.

On December 21, 1960, Union and the Staff executed a "Stipulation of Facts" which was made a part of the record and such stipulation stated, among other things, that "there are no unresolved factual matters, but only unresolved and disputed questions of law." In addition, extensive evidentiary material was received in evidence.

Despite the language above quoted, it appears clear from the stipulation, read as a whole, and the statements of counsel for Union and Staff counsel made during the hearing that there exists a substantial difference between the parties as to the meaning and effect reasonably attributable to the facts on which an agreement was reached. The Staff and Union disagrees regarding the effect which the proposed hydroelectric development will have or is reasonably capable of having upon the navigability of the Black River.

The Black River is downstream from the confluence of Taum Creek and the East Fork of the Black River and is part of the navigable waters of the United States, being navigable from a point at the mouth of the East Fork four miles below the site of the proposed dam, to the mouth of the Black River.[2]

The position of Union on the law [3] is to the effect that before the licensing provisions under the Act become applicable in this proceeding the Staff of the Commission must prove that the construction, maintenance, and operation of the project works on the navigability of the Black River will be "both substantial and inevitable."

The cases cited by Union do not contain any definition of the term "substantial" which could be said to be helpful in evaluating the facts agreed upon in this proceeding. Specifically, the cases cited do not spell out the degree to which navigability must be affected to be considered "substantial." A reading of the cases

[1] See Section 4(e) and 23(b) of the Federal Power Act.

[2] The "Stipulation of Facts" sets forth at page 11 that:

"There is a documentary evidence showing that the Black River is navigable from a point at the mouth of the East Fork, four miles below the site of the proposed dam, to the mouth of said Black River, House of Representatives Document No. 102, 73d Congress, 1st Session, notes on Appendix 1—Sheet No. 7, shows a Corps of Engineers' determination that 'the head of navigation for floating ties and timber' of the Black River is at or near the mouth of the East Fork. This determination was made in the engineering studies that preceded the construction of Clearwater Dam." There was no evidence of any facts to the contrary of the above quoted statements contained in the stipulation, or in the documentary material received in evidence. In the circumstances the only reasonable conclusion as to navigability is that set forth in the text hereinabove."

[3] See, for example, pp. 6 and 10 of Union's brief.

cited by Union [4] illustrates that the term "substantial" as used by Union has been interpreted by the courts or the Commission to mean an effect which is "serious," "appreciable," "measurable," or "pronounced," and not an effect which is merely "*de minimis*." The facts in the cases cited by Union demonstrate that despite the adjectives which have been quoted that what is meant by the courts as being "substantial" insofar as the effect on navigability is concerned is in large part dependent upon the evaluation of specific sets of circumstances by the persons authorized by law to decide the cases, *i.e.*, the regulatory agencies or the courts. This evaluation of the effect of a particular project works as being "substantial" or "appreciable" or the employment of some other adjective in describing the effect on navigability is largely a matter of judgment in particular circumstances and the circumstances of a past project are seldom so similar to a project under consideration as to be precedential.

In this case Union's position is that the construction, operation, and maintenance of the Taum Sauk project works, is capable of having only an insignificant or *de minimis* effect upon the navigability of the Black River.

The Staff's position, on the other hand, is that the facts agreed upon show that the project works are capable in certain circumstances of having a "measurable" or "pronounced" effect. The Staff's position is that the stipulated facts and the evidentiary support found in the exhibits received reflect a capability that the project works will have a substantial effect upon the navigability of the Black River and that therefore the license provisions are applicable. It will be observed, in this connection, that the test of jurisdiction invoked by the Staff is markedly different from that sought to be applied by Union. Union's position goes in an opposite direction to that advocated by the Staff as the appropriate test. It is Union's position that the "capability" test advocated by the Staff is not the law. Union urges on the contrary that to establish licensing jurisdiction it must be shown that the construction, operation, and maintenance of the project works will have an "inevitable" effect on the navigability of the Black River. As Union employs the term "inevitable" it means that Union considers that under the law the Staff must show that the construction, operation, and maintenance of the Taum Sauk project works will necessarily or will be practically certain to result in affecting the navigability of the Black River.

To support its claim that before the licensing provisions become applicable it is requisite that the Staff show that the operation of the project works will have an "inevitable" effect on navigation on the navigable waters of the United States, Union relied heavily upon opinions expressed in *United States* v. *Appalachian Electric Power Co.*, 23 F. Supp. 83, 105, and *United States* v. *Appalachian Electric Power Co.*, 107 F. 2d 769, 790. In connection with the opinion of the Court of Appeals in the Appalachian case Union pointed out that when the Supreme Court [5] reversed such court it held that the New River at the dam site was navigable and further held that the Federal Power Commission could impose license conditions having no relationship to navigation when the project works were to be constructed on navigable waters of the United States. Union contends, however, that the opinion of the Court of Appeals was not reversed by the Supreme Court insofar as such opinion sets forth standards by which it may be determined whether the license provisions under the Act are applicable to hydroelectric project works which are not situated on navigable waters of the United States, as is the instant case.

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[4] *E.g., Presque Isle County Electric Cooperative Association*, 8 FPC 687, 688; *Niagara Mohawk Power Corp.*, 10 FPC 715, 716; *Citizens Utilities*, 21 FPC 233, 241; *Clam River Dam Company*, 2 FPC 953; *Brazos River Conservation and Reclamation District.*

[5] 311 U.S. 377.

The distinction sought by Union to be made between the present proceeding and the determination of the Supreme Court in the Appalachian case is that the project works in Appalachian were found by the Supreme Court to be on navigable waters of the United States whereas in this case the agreed upon facts are that the dam site is not on navigable waters. Based upon this distinction, Union contends that the Supreme Court decision in Appalachian was not a reversal of the principles adverted to in the Court of Appeals opinion where the Court considered that the dam site was not on navigable waters. Union contends that in the latter situation the Court of Appeals decision in Appalachian is still good law, and established a precedent which should be applied here.

It is true that in this case it is clear that the project works will not be on navigable waters of the United States. Union contends therefore that a factual showing that the construction and operation of the project works are not on navigable waters of the United States but will only have the capability of affecting the navigability in a stretch of water downstream which concededly is part of the navigable waters of the United States is not an adequate basis to establish that the Commission's licensing authority under the Federal Power Act is applicable.

The Staff has cited a number of recent cases to support its position as to the appropriate base on which to test jurisdictional authority, and *Citizens Utilities Co.* v. *Federal Power Commission*, 279 F. 2d 1 (1960), and *Carolina Aluminum Co.*, 19 FPC 704 (1958), cited by the Staff appear to be directly in point. These cases hold that where a showing is made that the construction, operation, and maintenance of hydroelectric project works located on non-navigable waters is capable of having a measurable effect on navigable waters of the United States downstream that then the licensing provisions of the Act are applicable.

In the *Citizens Utilities* case, the Court of Appeals for the Second Circuit held that the Commission had licensing jurisdiction where private hydroelectric dams were constructed across a river at a point where there was a question whether the river was navigable but where the operation of the dams was capable of affecting temporarily the flow of water at a lower point in the stream which was navigable and did so in the ordinary operations of such dams.[6]

Accordingly, it is clear that where dams are proposed to be constructed even on a non-navigable stream, which are capable in their ordinary operation of affecting measurably the flow of water at a lower point of the river which is navigable the law is that the Commission's jurisdiction attaches and the licensing provisions are applicable.

Further, it appears that the holding in the Citizen's case is inconsistent with the rigid test of "inevitability" to establish jurisdiction which would be imposed by Union.

In *Carolina Aluminum Company*, 19 FPC 704, the company proposed a dam on non-navigable water but it was found as fact that its operation was capable of having an effect on navigability at points downstream in navigable waters of the United States. The Commission held that the project works were

[6] The Court noted in this case that the Commission's presiding examiner had found that the Clyde River was not "navigable water of the United States" except for the first 4,800 feet from its mouth; that the Commission had reversed the examiner on this point and held that the river was navigable at the dam site; and that the company was required to obtain a license. The Court of Appeals, apparently, did not find it necessary to resolve the question as to the navigability of the river at the dam site holding that the licensing provisions of the Act were applicable because of the effect of the project works on the navigable waters downstream apparently without regard to whether the waters at the dam site were or were not navigable.

subject to the licensing provisions under the Act. In this connection, the Commission adopted language in the decision of the presiding examiner reading as follows:

> In determining the jurisdiction of this Commission based upon the down stream effect of any hydroelectric development on navigable capacity, such jurisdiction does not depend upon the manner in which a hydroelectric development has been operated in the past or is proposed to be operated in the future but upon the effect which such hydroelectric development *is capable of having upon navigable capacity at points downstream.* Moreover, each hydroelectric development may, for the purpose of determining the question of jurisdiction arising from downstream effect, be considered and treated as if no other hydroelectric development were located within the stream either above or below the development, which is the subject of the jurisdictional inquiry. [Emphasis supplied]

It appears that if a proposed hydroelectric development on a non-navigable stream is capable of having a measurable effect on navigable capacity at points downstream in waters of the United States which are navigable that then the proposed project works are subject to the licensing provisions under the Act, and the law does not require a showing that the effect on navigability is inevitable. For example, the fact that a stream has acted in a specific way numerous times in the past may establish the probability that it will act similarly again in the future and will surely establish that it has the capability of acting that way in the future. It would not necessarily establish, however, that it would do so inevitably. To require the establishment of an "inevitable" effect would be unrealistic.

As we have noted the Taum Sauk project works will involve, among other things, the construction of two pools, one of which has been referred to as the "lower pool" and the other the "upper pool." In general, it is contemplated that at night or during periods of lesser consumer demand for electric power, the company will pump water from the lower pool to the upper pool and that in the daytime or other periods when more power is required for carrying peak loads on Union's system, the water in the upper pool would in the generation of electricity flow down to the lower pool. It is expected that the water in the upper pool will be allowed to flow back through a long pressure tunnel or conduit (6,400 feet long) into the lower pool as part of a daily cycle, *i.e.*, there would be pumping during the off-peak hours using available steam-generated electric energy and releasing the stored energy during the peak hours.

The facilities are different from the type of hydroelectric facilities which use the potential energy in natural flows of the stream to generate electric energy and which alternately store and release the natural flows from a stream. As Union contemplates the operation water will be impounded only one time in the lower pool, causing a temporary reduction in the downstream stage and thereafter on a daily cycle the water in the lower pool will be pumped up to the upper pool and later released.

After the impounding of the water in the lower pool has been completed, it is expected by Union that water will be discharged through or over the dam in amounts equal to the inflow into the lower pool from the streams above and that, therefore, the streams below the project will not be affected by the existence or operation of the plant. On this basis it is claimed that there will be no effect on the navigability of the Black River.

The Staff, on the other hand, claims that when physical conditions are considered in connection with the construction, maintenance, and operation of the project works, particularly in regard to the drainage conditions in the Upper

Black River Basin and when the water flows which have been measured over past years are considered the only reasonable conclusion to be reached is that the project works have the capability of affecting the navigability of the Black River. The facts relating to the size, physical characteristics and operation of the project works have been described hereinabove.

Based upon the conceded facts regarding the drainage in the upper Black River Basin and readings made at four stream gaging stations[7] located below the site of the dam for the lower pool, mathematical calculations were made, which were not challenged, from which a flow duration curve was drawn indicating that the flows at the proposed dam of the lower pool have:

(1) equaled or exceeded 50 cubic feet per second approximately 50 percent of the time;

(2) equaled or exceeded 100 cubic feet per second about 25 percent of the time;

(3) equaled or exceeded 200 cubic feet per second about 10 percent of the time;

(4) have exceeded 2,000 cubic feet per second less than one-half of one percent of the time; and

(5) have exceeded 7,000 cubic feet per second on three occasions.

These varying flow conditions when considered together with the physical character of the project works are capable of affecting navigability on the Black River in differing degrees dependent in large part upon the flow conditions at the times being considered. In this connection, the Staff has given consideration to five situations where the proposed project works would be capable of affecting the navigability of the Black River, *to wit*, (a) the effect on navigable capacity during the filling period; (b) the effect of the navigable capacity during high flow periods; (c) the effect on navigable capacity during malfunctions of facilities; (d) the effect on navigable capacity during emergency operation of the Taum Sauk plant; and (e) the effect on navigable capacity during average flows and normal operation of the Taum Sauk project works.

Three of these situations involve flow conditions such as have actually existed in the comparatively recent past. A fourth situation involves the possibility of malfunctions of facilities, and the fifth situation involves the problem of emergency operation of the project works.

The first set of circumstances considered are those relating to the effect on navigable capacity during the filling perid. The company has considered that the filling period would occur only once in the operation of the project. The Staff has pointed out that the lower pool will be filled not only during the initial operation of the project but also that there will be an emptying of the lower pool regularly during the normal operation of the project. The effect on the navigable water during the normal cycle through the pumping of the water from the lower pool and the return of the water during periods of generation of electricity will be dependent upon flow conditions at the time, and these flow

[7] The four stream gaging stations are located as follows: (1) a stream gaging station at Lesterville on the East Fork of the Black River, 3.3 river miles downstream from the site of the dam for the lower pool which measures the flow from a drainage area of 94.5 square miles; (2) a stream gaging station called Annapolis on the Black River 11 miles below the mouth of East Fork which measures the flow from a drainage area of 484 square miles of the combined three forks of the Black River and of its main stem below the mouth of the East Fork; (3) a stream gaging station at Leeper, Missouri, about 37 miles below the mouth of the East Fork of Black River measuring the discharge from drainage area of 957 square miles; and (4) a stream gaging station 40 miles from the dam of the river at Poplar Bluff, Missouri, measuring the discharge from a drainage area of 1245 square miles.

conditions are unpredictable specifically as to time or volume years in advance but the records maintained in the past show a wide variance in flow conditions at various times. Moreover, there would be normally the problem of regular inspection and maintenance for repair of the project works which could require the emptying of either or both of the pools involved.

It is clear enough that the lower pool will initially hold back water from the East Fork of the Black River and that this will reduce the natural flow below the dam, thus affecting the storage and flow of the East Fork of the Black River. The degree to which this operation will affect the flow below the dam and the navigability in the Black River is dependent upon the amount of inflow to the lower pool from the East Fork and the amount of the total flow retained for storage. As has been pointed out the flows in the proposed dam of the lower pool have equaled or exceeded 100 cubic feet per second about one quarter of the time. Dependent upon how the operations were conducted, it appears that if the flow during the impoundage of the lower pool from the streams above the dam were at the rate of 105 cubic feet per second (as they are about one-fourth of the time) and if 50 cubic feet per second were stored, the lower pool would be filled in approximately 63 days. In the latter case, the stage or the water surface level of the Black River at the Annapolis gage during such circumstances would be reduced by about a tenth of a foot and the water surface level on the East Fork about 3.7 miles below the dam site would be reduced about one foot.

If the flow were at 105 cubic feet per second, and all the flow were retained the pool would be filled in somewhat less than 32 days and the stage of the Black River would be reduced by about two-tenths of a foot and the stage on the East Fork about 3.7 miles below the dam site would be reduced by about 2 feet.

If there were higher flows during impoundage, the pool could be filled very quickly.

While the flows in the proposed dam of the lower pool have exceeded 2,000 cubic feet per second, less than one-half of one percent of the time the fact is that such flows have occurred in the past, and there is no good reason to assume that such flows will not occur again. If the flow were 2,000 cubic feet per second and one-half of that were stored, the surface level in the Annapolis gage would be reduced about 0.5 feet and the stage 3.7 miles below the dam on the East Fork would be reduced by 0.8 feet.

There have been a number of occasions in comparatively recent years when high-flow conditions have been experienced. The record shows that there were high-flow conditions experienced during June 6–10, 1945, January 23–24, 1949, and May 9–10, 1960. Had the project works been in existence in the 1945 flood period the natural maximum stage below the dam of the upper pool would be reduced by about 0.3 feet, and the maximum peak flow past the dam would be reduced from 33,200 to 30,800 cubic feet per second.

In the high flow period of January 1949, the generating cycle would have added to the natural peak flow past the dam of the lower pool by increasing it from 17,600 cubic feet per second to 21,800 cubic feet per second and the dam at the lower pool would reduce the natural stage below the dam by 0.2 feet to 0.4 with no plant operation.

For high-flows, such as that of May 9–10, 1950, and with operation of the plant, the pumping cycle of itself would reduce the natural stage below the dam of the upper pool by about 0.8 feet, but the generating cycle would increase the stage below the dam above natural stage by about one foot.

During stream flows of 2,800 feet per second or less into the lower pool and for the normal cycles of generation and pumping for the project works there

would be no increase or decrease in the natural stage and flow below the project works, assuming no emergency operations, and no malfunctions of facilities. If an electric power emergency were to occur requiring a rapid change from a pumping cycle at the rate of about 5,000 cubic feet per second and the lower pool were about full there would be an increase of about 9,000 cubic feet per second in the flow below the dam.

As we have noted hereinabove when the two motor driven pumps to bring water to the upper pool are operating together at 200 revolutions per minute they will deliver about 5,000 cubic feet per second to the upper pool and the average turbine discharge while generating may average as much as 6,800 cubic feet per second. The change from pumping to generation in such circumstances would increase the stages as follows: 2.4 feet below the dam, 1.6 feet at Lesterville and about one foot at Annapolis gage.

It is clear that operation during emergency conditions has the capability to affect navigability on the Black River.

It cannot reasonably be said that the possibility of malfunction or mechanical failure does not exist in this project. There certainly exists the possibility of human or mechanical failure. In this project the possibility of such failure exists through the improper operation of stream gages, failure of the stream flow facilities to record correctly the inflows and outflows or to transmit flow information to the control points, clogging of the intake to sluiceway works, or failure of facilities. If there were malfunction during periods of flood and the generators were employed it would affect navigability severely, particularly because the effect of generation would be to add to the unusual accretion of water.

Under conditions where the natural flows were 105 cubic feet per second in the East Fork and 582 cubic feet per second in the Annapolis River at the Annapolis gage and if it be assumed that the lower pool were full to elevation of 750 feet above mean sea level, the sluice in the dam were closed and not operated, and a generating cycle were started and continued until all the water were withdrawn from the upper pool the result would be that the stage of the East Fork immediately below the dam would be increased by 7.0 feet; the stage at the Lesterville gage would be increased by 5.7 feet; the stage at the Annapolis gage would be 3.4 feet.

If under the described conditions there were a reversal from generation to pumping, all of the flow below the dam would be shut off and there would be a reduction at the Annapolis gage of 0.2 feet.

Another possibility, which as the Staff points out, could occur at any time, would be the effect on navigability of incorrect operation of the sluiceway. For example, during the month of August if there were a condition of low flow such as a flow of 5 cubic feet per second into the lower pool and 107 cubic feet per second in the Black River at the Annapolis gage and the Taum Sauk project works were not in operation, the abrupt release of water through the sluiceway could result in the dumping of 2,000 cubic feet per second from the lower pool. This would cause the stage just below the dam to rise about 5.5 feet; the stage at Lesterville would increase about 4.4 feet; and the stage at Annapolis would increase approximately 2.2 feet.

The flow conditions described hereinabove have been scientifically determined to have existed in the past. There is no reason to believe that they will not occur again. In fact, ordinary prudence would dictate an opposite conclusion. In addition the possibility of malfunction is always present. The impact of the flow conditions and the construction, operation, and maintenance of the project works upon the navigability of the Black River would vary from a *de minimis* effect

to a substantial effect. Most of the time navigability on the Black River would not be substantially affected but there will be times when it will be affected. The problem to be resolved, however, is not whether the Commission should extend its attention to situations where the effect on navigability is not always substantial or is not continuous but whether under the law navigability will be affected to a measurable degree by the maintenance, construction, and operation of the project works.[8] Here it will be so affected.

An additional issue raised by the Staff is whether Union was required to obtain a license under the Act because the Taum Sauk Project will be constructed, maintained, and operated by Union to supply markets outside the State of Missouri thereby affecting the interests of interstate or foreign commerce, The Staff contends that on this basis alone, a license would be required under the Act.

The sole issue in this case is whether or not Union is required to obtain a license to construct, operate, and maintain the Taum Sauk Project works. That issue has been decided in the affirmative for the reasons which have been set forth hereinabove. It is, therefore, unnecessary and may not be desirable to pass upon the second basis urged by the Staff for requiring Union to obtain a license. Sufficient ground has already been established upon which it must be held that the Commission has jurisdiction and that Union must obtain a license for its Taum Sauk Project works.

In connection with the additional issue raised by the Staff, the "Stipulation of Facts" shows that Union supplies markets outside the State of Missouri and that the operations of the Taum Sauk Project will serve to supply such markets. In substance, the facts contained in the stipulation show that Union operates an interstate electric system, including two hydroelectric stations, seven steam electric stations, transmission lines with voltages of 230 kv, 161 kv, 138 kv, 110 kv, and 69 kv, plus associated substation facilities, and distribution facilities; that it is a member of the Illinois-Missouri Pool, sharing in its operations, obligations and benefits; that it sells electric energy in the States of Missouri, Illinois and Iowa; that it is interconnected with other electric utilities including some which operate outside the State of Missouri; that power flows over transmission lines of Union, from Missouri to Illinois, from Illinois to Missouri, from Iowa to Missouri, from Iowa to Illinois and from Illinois to Iowa; that it has been receiving firm capacity and reserves from the Illinois-Missouri Pool; that the Taum Sauk Project will be interconnected via two 138 kv circuits to the Union interstate network; that the Taum Sauk Project works will provide an instantaneous reserve available to pick up load in event of breakdown of other generating equipment connected to the interstate network.

It has been concluded that it is requisite under the law with regard to the effect on navigability that Union obtain a license for the construction, maintenance and operation of its Taum Sauk Project works without regard to the fact that it will supply markets outside the State of Missouri with energy obtained through the operation of the Taum Sauk Project. Accordingly, it is not necessary to pass upon the legal effect insofar as the licensing requirements are concerned because of the supply of electricity which would be transmitted to interstate markets by reason of the construction and operation of the Taum Sauk Project. A showing that the Taum Sauk Project works will have a measurable effect on the navigability of the Black River which is part of the navigable waters of the United States is a sufficient showing to establish that a license must be obtained from the Commission.

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[8] *Cf. Connecticut Co.* v. *F.P.C.*, 324 U.S. 515, 536.

ADDITIONAL FINDINGS AND CONCLUSIONS

Upon consideration of the entire record made in this proceeding, the "Stipulation of Facts," all the evidence adduced, the briefs filed herein, and the matters relevant to a decision herein, the Presiding Examiner finds and concludes in addition to the findings and conclusions hereinabove stated that:

(1) Union Electric Company (Union Electric or Declarant) is a Missouri corporation operating an integrated electric system in the States of Missouri, Illinois, and Iowa.

(2) Union Electric filed a declaration of intention pursuant to Section 23(b) of the Federal Power Act announcing its proposal to construct, operate and maintain pumped-storage hydroelectric project works which are referred to as the Taum Sauk Project.

(3) Taum Sauk Project will be located in Reynolds County, Missouri, in or along the East Fork of Black River, about 294 miles above the mouth of Black River and just below the confluence of Taum Sauk Creek with the East Fork.

(4) Taum Sauk Project will be located about 4 miles above the mouth of the East Fork of Black River.

(5) The East Fork of Black River empties into Black River about 289.5 miles above its mouth.

(6) The Black River, from its mouth to its confluence with the East Fork, is a navigable water of the United States.

(7) Taum Sauk Project works will include, among other things, a lower dam forming a lower pool backing water up the East Fork and Taum Sauk Creek, a powerhouse including two 175,000 kilowatt units each having pump-turbine and motor-generator equipment and associated facilities, and an upper pool.

(8) Union Electric has filed application for license and construction is now under way on project works of the Taum Sauk Project, except those which will affect the East Fork at the site of the lower dam.

(9) When the project works generate electric power and energy, water from the upper pool, up to a maximum of 4,350 acre-feet, will be discharged into the lower pool.

(10) When the project works pump water from the lower pool, up to a maximum of 4,350 acre-feet will be lifted to the upper pool.

(11) The dam for the lower pool of the project will have a free crest spillway capable of discharging 70,000 cubic feet per second when the water surface is 763 feet above mean sea level and 80,000 cubic feet per second at water surface elevation of 764 feet above mean sea level.

(12) A sluiceway will be provided in the dam for the lower pool, capable of discharging 2,000 to 2,800 cubic feet per second.

(13) An operating stream gaging station was established at Lesterville, Missouri, in January 1960, measuring the flow from a drainage area of 94.5 square miles of the East Fork of Black River.

(14) An operating stream gaging station, called Annapolis, was established in 1939 on the Black River about 11 miles below the mouth of East Fork, river mile about 279, measuring the flow from a drainage area of 484 square miles of the combined three forks of Black River and of its main stem below the mouth of the East Fork.

(15) The drainage area of the East Fork at the site of the dam of the lower pool of Taum Sauk Project is 88 square miles.

(16) The average flow of the East Fork of Black River at the site of the dam of the lower pool is about 105 cubic feet per second.

(17) The average flow of the Black River at the Annapolis gage over an 18 year period is 582 cubic feet per second.

(18) Except for high flows and for low flows, the flows of the East Fork of Black River at the dam site for the lower pool of Taum Sauk Project may be estimated with reasonable accuracy by applying the ratio of drainage areas to the measured discharges at the Annapolis gage.

(19) A maximum discharge of 45,400 cubic feet per second at the Annapolis gage occurred on June 8 and 10, 1945.

(20) The maximum discharge at the dam site of the lower pool of the Taum Sauk Project was about 33,200 cubic feet per second during the June 8–10, 1945, flood.

(21) The Federal Clearwater flood control dam is located on the Black River 30 miles downstream from the mouth of the East Fork of Black River.

(22) Some lands above the Taum Sauk Project within the drainage area of the East Fork were acquired as part of Clark National Forest in the interest of flood control and other purposes.

(23) During each and every impoundage of water in the lower pool from streams above, the stage and flow of the East Fork and of the Black River from its confluence with the East Fork downstream to the Annapolis gage and below would be reduced, the amounts depending on the inflow and the percentage thereof retained for storage.

(24) During each and every impoundage of water in the lower pool from streams above, the stage at Lesterville gage would be reduced by 0.8 to 3.7 feet.

(25) During each and every impoundage of water in the lower pool from streams above, the stage at Annapolis gage would be reduced by 0.1 to 0.5 feet, depending on the inflows and the portions retained.

(26) At times of inflows in excess of 2,000 to 2,800 cubic feet per second from streams above into the Taum Sauk lower pool and under the proposed method of operation of project works, the stage and flow of the East Fork below the dam and of the Black River from its confluence with the East Fork downstream to the Annapolis gage and beyond, would be changed from the stage and flow that would exist under natural conditions, sometimes there being an increase in stage and flow and at other times there being a decrease in stage and flow depending on the operating phase of the Tam Sauk Project works.

(27) At times of inflows of 9,000 cubic feet per second and above, from streams above into the Taum Sauk lower pool, generation at the project works would cause an increase of about 1 foot in stage at the Annapolis gage on the Black River.

(28) Under conditions of the lower pool being full, the sluice closed, and average flow in the East Fork and Black River, a generating cycle at full load for 8 hours at the Taum Sauk Project would cause increase in stages as follows: 7.0 feet below the dam, 5.7 feet at the Lesterville gage, and 3.4 feet at the Annapolis gage.

(29) An abrupt release of water through the Taum Sauk sluiceway during a low flow period, assuming no operation of project works, would cause increase in stages about as follows: 5.5 feet below the dam, 4.4 feet at Lesterville gage and 2.2 feet at Annapolis gage.

(30) An emergency operation of Taum Sauk Project would cause a change in stage and flow of Black River from its confluence with the East Fork and below to Annapolis gage and below if the flows are of large magnitude.

(31) The proposed Taum Sauk Project will be capable of affecting, and will affect the navigable capacity of the Black River downstream from its confluence with the East Fork to the Annapolis gage and beyond, thereby affecting the interests of interstate or foreign commerce.

(32) The proposed Taum Sauk Project will be constructed, operated and maintained for the development of power to supply markets not only in Missouri but also in the State of Illinois, thereby affecting the interests of interstate or foreign commerce.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal pursuant to its Rules of Practice and Procedure that Union Electric Company is required to obtain a license for its proposed Taum Sauk Project works, pursuant to the provisions of the Federal Power Act and the Commission's Rules of Practice and Procedure.

SAMUEL BINDER,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

FORT SMITH GAS CORPORATION, DOCKET NO. CP62-101

FINDINGS AND ORDER DIRECTING PHYSICAL CONNECTION OF FACILITIES AND SALE OF NATURAL GAS

(Issued April 20, 1962)

On October 19, 1961, Fort Smith Gas Corporation (Applicant) filed in Docket No. CP62-101 an application pursuant to Section 7(a) of the Natural Gas Act for an order of the Commission directing Mississippi River Fuel Corporation (Mississippi) to establish physical connection of its facilities with those which Applicant proposes to construct and operate, and to sell and deliver to Applicant natural gas for resale and distribution in the Towns of Biggers, Reyno, and Datto, Arkansas, and their environs, all as more fully set forth in the application.

Applicant proposes to construct and operate a total of 1.69 miles of individual 2-inch lateral transmission pipelines extending from three separate connections on Mississippi's main line to each of the three towns. Through these facilities Applicant will supply the natural gas requirements of the communities which are estimated to be as follows:

Requirements in Mcf at 14.73 psia

	Year of Service		
	1st	2d	3d
Peak day	408	419	427
Annual	44,909	46,895	51,955

Applicant will finance the required facilities, estimated to cost $82,672, with funds obtained through the issuance of short-term notes which notes may be refinanced at a later date, if necessary, with the issuance of long-term financing.

Applicant has obtained franchises from the Towns of Biggers, Reyno, and Datto, and has obtained a certificate of public convenience and necessity from the Arkansas Public Service Commission.

Due notice of the filing of the subject application and opportunity for hearing thereon has been given by publication in the Federal Register on March 22, 1962

(27 FR 2712). No protest to the granting of the application or petition to intervene has been filed in this proceeding.

The Commission finds:

(1) Applicant, Fort Smith Gas Corporation, an Arkansas corporation having its principal place of business in Fort Smith, Arkansas, is a natural gas distribution utility under the jurisdiction of the Arkansas Public Service Commission and is duly authorized to sell and distribute natural gas in the State of Arkansas.

(2) Mississippi River Fuel Corporation, a Delaware corporation having its principal place of business in St. Louis, Missouri, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of March 1, 1944, in Docket No. G–291 (4 FPC 535).

(3) It is necessary and desirable in the public interest to direct Mississippi to establish physical connection of its transmission system with the facilities which Applicant proposes to construct and operate and to sell and deliver to Applicant up to 427 Mcf of natural gas per day for resale in Biggers, Reyno, and Datto, Arkansas, as hereinbefore described and as more fully described in the application in this proceeding.

(4) The requirement that Mississippi serve Applicant, as proposed herein, will not place an undue burden upon Mississippi nor impair its ability to render adequate service to its existing customers.

The Commission orders:

(A) Mississippi River Fuel Corporation be and it is hereby directed to establish physical connection of its transmission system with the facilities which Fort Smith Gas Corporation proposes to construct and operate and to sell and deliver up to 427 Mcf of natural gas per day for resale in Biggers, Reyno, and Datto, Arkansas, as hereinbefore described and as more fully described in the application in this proceeding, provided that Applicant is ready to accept service within one year from the date of this order.

(B) Mississippi shall report to the Commission in writing and under oath the date of commencement of service to Applicant hereunder within ten days thereof.

(C) In the event that Mississippi is unable to meet the requirements of Applicant from its existing capacity as it has been allocated in *Arkansas-Louisiana Gas Company, et al.*, Docket Nos. G–17567, *et al.*, Opinion No. 355, issued April 18, 1962, *supra* p. 697, and requires modification of the allocation made therein, then Mississippi may file an appropriate application for modification of said Opinion.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

SACRAMENTO MUNICIPAL UTILITY DISTRICT, PROJECT NO. 2101

ORDER APPROVING REVISED EXHIBIT L DRAWING

(Issued April 20, 1962)

On March 9 and 28, 1962, Sacramento Municipal Utility District, licensee for major Project No. 2101, filed for Commission approval revised Exhibit L drawing for the Loon Lake Dam.

The principal changes shown on the revised drawings are a redesign of the spillway at the Loon Lake Dam from a straight overflow type to a side channel type discharging into Gerle Creek near the toe of the dam, and elimination of

berms in the dam design. A ford is proposed across the spillway channel at its lower end rather than a roadway across the spillway.

In its March 7, 1962, letter transmitting the revised drawings, the licensee advised that realignment of the spillway was necessary because the Forest Service had objected to spill being directed down a deep ravine which would cause erosion problems. The ford across the spillway channel at its lower end has been agreed to by the Forest Service which specified that a road be built at either end of the ford to a grade not to exceed eight percent.

The removal of berms (not required by the license) from the dam design will not affect the safety of the structure, and a Commission staff check on the spillway capacity shows it to be adequate.

The Commission finds:

(1) The following described revised Exhibit L drawings conform to the Commission's rules and regulations and should be approved as part of the license for the project, except to the extent that Exhibit L–98 (FPC No. 2101–160) and Exhibit L–100 (FPC No. 2101–162) show a road at either end of the ford built to a grade of 10 percent, which is 2 percent greater than the maximum grade agreed to with the Forest Service:

Exhibit L–98 (FPC No. 2101–160) entitled "Loon Lake Main Dam, General Arrangement, Plan and Profile," except for the indicated grade of the road at either end of the ford;

Exhibit L–99 (FPC No. 2101–161) entitled "Loon Lake Main Dam, General Arrangement, Sections and Details" and

Exhibit L–100 (FPC No. 2101–162) entitled "Loon Lake Spillway, Excavation, Plan, Profile, and Sections," except for the indicated grade of the road at either end of the ford;

(2) Exhibit L–18 (FPC No. 2101–139), now part of the license and which has been superseded, should be eliminated from the license.

The Commission orders:

The revised Exhibit L drawings described in finding (1) above are approved as parts of the license for Project No. 2101 to the extent indicated and the superseded Exhibit L drawing described in finding (2) above is eliminated from the license for the project.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

UNITED STATES DEPARTMENT OF THE INTERIOR, SOUTHEASTERN POWER ADMINISTRATION, JOHN H. KERR AND PHILPOTT PROJECTS, DOCKET NO. E–7002

SUPPLEMENTAL ORDER AMENDING ORDER CONFIRMING AND APPROVING RATES AND CHARGES

(Issued April 20, 1962)

By order issued December 21, 1961, 26 FPC 913, in the above-entitled matter, the Commission, pursuant to the provisions of the Flood Control Act of 1944 (58 Stat. 887), confirmed and approved *inter alia* for a period beginning December 21, 1961, and ending June 30, 1965, Wholesale Dump Energy Rate Schedule KP–2, applicable to sales of dump energy generated at the John H. Kerr and Philpott projects to Virginia Electric and Power Company (Vepco) and Carolina Power and Light Company (Carolina Power).

By letter dated March 27, 1962, the Secretary of the Interior, on behalf of the Southeastern Power Administration, filed with the Commission for its confirmation and approval, for a period beginning with the date of issuance of the Commission's order and ending on June 30, 1965, Wholesale Dump Energy Rate Schedule KP–2 (Revised), which would supersede Rate Schedule KP–2 for sales of dump energy generated at the two projects to Vepco and Carolina Power. The revised rate schedule differs from its predecessor only in that the monthly energy charge to each company is an amount equal to 80 percent, instead of 85 percent, of the saving in the cost of fuel in the Company's operating generating stations due to the generation avoided therein by the receipt of dump energy from the afore-mentioned projects.

The Secretary of the Interior advised that the present rate schedule is unsatisfactory from the standpoint of maximum utilization of the Federal Government's power resources because sales thereunder result in a periodic waste of water and an accompanying loss of revenue.

The repayment study for the John H. Kerr and Philpott projects indicated that anticipated revenues from the sale of dump energy under the original Rate Schedule KP–2 would aggregate approximately $83,800 annually, but actual revenues totaled a smaller amount because of the lack of marketability of dump energy at that rate level. The Secretary states that sales of energy under the revised rate schedule will produce more revenue than under the original one, and that total revenues expected from such sales will be approximately $78,800 annually. Notwithstanding the reduction in previously estimated revenues from the sale of dump energy, it is anticipated that the investment costs of the projects will be repaid within a fifty-year repayment period.

The Commission finds:

Good cause has been shown and it is appropriate for the purposes of the Flood Control Act of 1944 that the Commission's confirmation and approval of the rates and charges for the John H. Kerr and Philpott projects contained in its order issued December 21, 1961, be modified as hereinafter provided.

The Commission orders:

The confirmation and approval of the rates and charges of the Southeastern Power Administration for the sale of power developed at the John H. Kerr and Philpott projects set forth in its order issued December 21, 1961, is hereby amended by substituting the rates and charges for the sale of fuel replacement energy contained in Wholesale Dump Energy Rate Schedule KP–2 (Revised) referred to in the recital above for those set forth in the original Wholesale Dump Energy Rate Schedule KP–2, which revised rates and charges shall be effective for a period beginning with the date of issuance of this order and ending June 30, 1965.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

IOWA SOUTHERN UTILITIES COMPANY, DOCKET NO. E–7032

ORDER AUTHORIZING THE ISSUANCE OF COMMON STOCK

(Issued April 25, 1962)

Iowa Southern Utilities Company (Applicant), incorporated under the laws of the State of Delaware, qualified to do business as a foreign corporation in

the States of Iowa and Illinois, and doing business in the State of Iowa, with its principal place of business at Centerville, Iowa, filed an application on March 29, 1962, as amended April 16, 1962, for an order, pursuant to Section 204 of the Federal Power Act, authorizing it to issue and sell 75,000 additional shares of its Common Stock, par value $15 per share.

Applicant proposes to enter into a Purchase Agreement for the sale of the new shares of Common Stock, with a group of underwriters headed by A. G. Becker & Co. Incorporated, Chicago, Ill. These underwriters have agreed to underwrite the new shares of Common Stock at a fee of 2.12% of the offering price to the public. The afore-mentioned fee represents the lowest cost of underwriting the contemplated issue on the basis of proposals submitted to Applicant by three underwriting firms.

The new shares of Common Stock are to be offered publicly on or about April 25, 1962, by the underwriters referred to above at $42.25 per share. The last offering price on April 24, 1962, of the Applicant's outstanding Common Stock, which is traded on over-the-counter market, was $42.00 per share.

By letter dated March 9, 1962, Docket No. IN–950, the Commission, pursuant to Section 34.2(k)(2)(ii) of its Regulations under the Federal Power Act, authorized Applicant to enter into negotiations for the underwriting and sale of the proposed issuance of Common Stock. Applicant now requests that the proposed issuance be exempted from the competitive bidding requirements of Section 34.1a (b) and (c) of those Regulations upon findings as set forth in Section 34.1a (a)(4) thereof.

Applicant proposes to utilize the proceeds from the issuance and sale of the new shares of Common Stock, estimated at approximately $3,100,000, to discharge bank loans (outstanding in the principal amount of $700,000 on April 1, 1962) and toward the payment of the cost of Applicant's 1962 and 1963 construction programs, estimated to cost $3,010,000 and $4,290,000, respectively. Of the total $7,300,000 for the 1962-63 programs approximately $5,350,000 will be spent for electric system facilities, $1,350,000 for gas system facilities and $600,000 for general plant facilities. The electric facility construction program includes $100,000 in 1962 for the purchase of a site for a future generating station south of Burlington, Iowa; $575,000 in 1963 for installation of a 6,000 kw diesel peaking plant at Centerville, Iowa; $375,000 for installation of additional generating equipment; and, $260,000 in 1962 and $190,000 in 1963 for construction of a 20 mile 69 kv transmission line from Albia to Centerville, Iowa. The gas facilities in Applicant's construction program consist of gas system mains and distribution extensions.

Written notice of the application has been given to the Iowa State Commerce Commission and the Illinois Commerce Commission, and to the Governor of each of those States. Notice of the application was also given by publication in the Federal Register on April 7, 1962 (27 F.R. 3360), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest with the Federal Power Commission, Washington 25, D.C., on or before April 24, 1962. No protest, petition or request to be heard in opposition to the granting of the application has been received.

The Commission finds:

(1) Applicant, a corporation, is a public utility within the meaning of Section 204 of the Federal Power Act, subject to the jurisdiction of the Commission as heretofore described and set forth in the Commission's order issued May 31, 1961, *Iowa Power and Light Company and Iowa Southern Utilities Company*, Docket No. E–6974 (25 FPC 1063).

(2) The proposed issuance of Common Stock as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) There is no affiliation, direct or indirect, through directors, officers or stockholders, or the ownership of securities, or otherwise, between Applicant and the underwriting firm of A. G. Becker & Co. Incorporated.

(4) The fees proposed to be paid to A. G. Becker & Co. Incorporated in connection with the proposed issuance of Common Stock do not appear to be unreasonable.

(5) Under the circumstances of this case, sufficient cause has been shown for exempting the proposed issuance of Common Stock from the competitive bidding requirements of Section 34.1a (b) and (c) of the Commission's Regulations under the Federal Power Act.

(6) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204(f) of the Act, and the proposed issuance of Common Stock, as described above, is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(7) The proposed issuance of Common Stock, as hereinafter authorized, will be for a lawful object, within the corporate purposes of Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The proposed issuance of Common Stock, as described above, upon the terms and conditions and for the purposes specified in the application, is hereby authorized, subject to the provisions of this order.

(B) This authorization shall expire unless the transaction hereby authorized is consummated within 60 days from the date of issuance of this order.

(C) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuations, estimates or determinations of costs, or any other matter whatsoever which is now pending or which hereafter may come before this Commission or any other regulatory body.

(D) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States in respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE, PROJECT NO. 2287

ORDER ISSUING LICENSE (MAJOR)*

(Issued April 25, 1962)

On December 27, 1960, Public Service Company of New Hampshire (Applicant) filed application for a license under Section 4(e) of the Federal Power Act (hereinafter referred to as "the Act") for its constructed Project No. 2287, known as the J. Brodie Smith Project, located on the Androscoggin River in the city of Berlin, Coos County, New Hampshire. The application recites that parts of the head included in the project have been used by various companies since the early 1850's, and that the dam serving the project was originally built

*Modified by order issued February 14, 1964, 31 FPC 417.

in 1885. All of the prior owners were industrial corporations which used the output in their respective businesses. Applicant, which was the first owner to utilize the entire head through a single development, acquired substantially all of the project lands by deed dated June 24, 1945, and immediately developed plans for reconstruction. Such reconstruction was commenced in August, 1945, and completed in May 1948.

In its order issued July 24, 1958,[1] the Commission found that the Androscoggin River throughout its entire length is a "navigable water" as defined in Section 3(8) of the Federal Power Act and a "navigable water of the United States" within the meaning of Section 23(b) of the Act. The basis for this finding was that the Androscoggin is presently, and for more than a century has been, used for the transportation of logs and other forest products by water.

Applicant requests a 50 year license effective as of the date of issuance. However, for reasons fully explained in our companion opinion No. 357 pertaining to Applicant's Project No. 2288 at Gorham, New Hampshire, we shall tender a license effective as of August 1, 1945—the first day of the month in which Applicant commenced its reconstruction with filing a license application or declaration of intention under Section 23(b) of the Act—and terminating December 31, 1993.[2]

The Secretary of the Army and the Chief of Engineers have approved the plans of the project structures insofar as the interests of navigation are concerned.

An Assistant Secretary of the Interior, in reporting on the application, recommended for inclusion in any license issued certain special conditions in the interest of fish life.

The Commission finds:

(1) Applicant is a corporation organized under the laws of the State of New Hampshire and has submitted satisfactory evidence of compliance with the requirements of all applicable state laws insofar as necessary to effectuate the purposes of a license for the project.

(2) The project consists of:

(a) All lands constituting the project area and enclosed by the project boundary or the limits of which are otherwise defined, and/or interest in such lands necessary or appropriate for the purposes of the project, whether such lands or interest therein are owned or held by the Licensee or by the United States; such project area and project boundary being more specifically shown and described by certain exhibits which formed part of the application for license and which are designated and described as follows:

Exhibit J: (FPC No. 2287–1) General Map of Project Area; and
Exhibit K: (FPC Nos. 2287–2 and –3) Detail Map of Project Area.

(b) Project works consisting of:

A masonry and concrete gravity-type dam comprised of two overflow sections equipped with hinged steel flashboards, two overflow sections equipped with

[1] New Hampshire Water Resources Board, Docket No. E–6807, 20 FPC 99–101.

[2] In our companion opinion we observed that in a case where unauthorized construction subsequent to 1935 "results in the replacement of substantially all existing facilities and the material enlargement of the scale of the project, there might conceivably be some basis for prescribing a license term ending 50 years from the date of such improvements." The present application does not disclose the extent of the reconstruction undergone by the project. However, pending a contrary showing by the Applicant, we can reasonably assume that the reconstruction in the present case was not of the magnitude contemplated by the above quotation from our companion order.

wood pipe supported flashboards, one overflow section equipped with two steel roller-type sluice gates, and one non-overflow masonry abutment section; a concrete arch-type diversion dam located in a former river channel just upstream from the powerhouse; a small reservoir with an area of about 8 acres and a normal water surface at elevations 1,009.7 feet (USGS datum); a canal about 500 feet long extending from the dam to an intake section; a steel pipeline from the intake to a surge tank; a surge tank; a penstock from the surge tank to the powerhouse; a powerhouse containing one 20,500-horsepower turbine connected to a 15,000-kilowatt generator; a step-up transformer; a 115 kv transmission line extending to the East Side substation; a control cable; and appurtenant facilities; the location, nature, and character of which are more specifically shown and described by the exhibits hereinbefore cited and by certain other exhibits which also formed part of the application for license and which are designated and described as follows:

Exhibit L: General Design Drawings.

FPC No.	Sheet No.	Description
2287-4	1	Dam Layout.
2287-5	2	Main Dam, General Plan and Elevation.
2287-6	3	Main Dam, Gate Piers.
2287-7	4	Main Dam, Flashboard Piers.
2287-8	5	Main Dam, Sections—Flashboard Spillway.
2287-9	6	Arch Diversion Dam, West Channel.
2287-10	7	Intake—General Plan.
2287-11	8	Intake—Upstream Elevation.
2287-12	9	Intake—Structural Steel Plan at El. 1016.0.
2287-13	10	Intake—Concrete Bascule Gate.
2287-14	11	Intake—Canal Walls and Floor.
2287-18	15	Surge Tank Location and Penstock Connection to Powerhouse.
2287-19	16	Grading and Paving Plan—Powerhouse Grounds.
2287-20	17	Powerhouse Equipment Plan Generator, Floor El. 955.75.
2287-21	18	Powerhouse—Basement Floor Plan.
2287-23	20	Powerhouse—Transverse Section, Centerline of Unit.
2287-24	21	Powerhouse—Elevations Upriver—Substructure.
2287-25	22	Powerhouse—Elevations Downriver—Substructure.
2287-26	23	Powerhouse—Brickwork, West and North Elevations.
2287-27	24	Powerhouse—Brickwork South and East Elevations.
2287-28	25	Powerhouse—Draft Tube Gates Location and Dimensions.

Exhibit M: Twelve typewritten pages, "General Description of Mechanical and Electrical Equipment", filed in the Commission December 27, 1960.

(c) All other structures, fixtures, equipment or facilities used or useful in the maintenance and operation of the project and located on the project area, including such portable property as may be used or useful in connection with the project or any part thereof, whether located on or off the project area, if and to the extent that the inclusion of such property as a part of the project is approved or acquiesced in by the Commission; also, all riparian or other rights, the use or possession of which is necessary or appropriate in the maintenance and operation of the project.

(3) No conflicting application is before the Commission. Public notice of the filing of the application has been given as required by the Act. No protests have been received.

(4) The issuance of a license as hereinafter provided will not affect a Government dam or the development of any water resources for public purposes which should be undertaken by the United States.

(5) The project is best adapted to a comprehensive plan for improving and developing the Androscoggin River for the use or benefit of interstate or foreign commerce, for the improvement and utilization of water-power development, and for other beneficial public uses, including recreational purposes, under the terms and conditions hereinafter imposed.

(6) The following described transmission and electrical facilities are parts of the project within the meaning of Section 3(11) of the Act and should be included in the license for the project as hereinafter provided:

(a) the 6.9/115 KV step-up substation adjacent to the powerhouse.

(b) the 115 KV transmission line from the step-up substation to the East Side substation.

(c) the switching facilities at the substation associated with the 115 KV transmission line.

(7) The installed horsepower capacity of the project hereinafter authorized for the purpose of computing the capacity component of the administrative annual charge is 20,000 horsepower.

(8) The amount of annual charges to be paid under the license for the purpose of reimbursing the United States for the costs of administration of Part I of the Act is reasonable as hereinafter fixed and specified.

(9) The energy generated by the constructive project is distributed and sold by Applicant for public utility purposes.

(10) The exhibits designated and described in finding (2) above conform to the Commission's rules and regulations and should be approved as part of the license for the project as hereinafter provided.

The Commission orders:

(A) This license is issued to Public Service Company of New Hampshire under Section 4(e) of the Federal Power Act for a period effective August 1, 1945, and terminating December 31, 1993, for the continued operation and maintenance of the J. Brodie Smith Development, Project No. 2287, located on the Androscoggin River, a navigable water of the United States, in the City of Berlin, Coos County, State of New Hampshire, subject to the terms and conditions of the Act, which is incorporated herein by reference as a part of this license, and subject to such rules and regulations as the Commission has issued or prescribed under the provisions of the Act.

(B) This license is also subject to the terms and conditions set forth in Form L–3, December 15, 1953, entitled "Terms and Conditions of License for Constructed Major Project Affecting Navigable Waters of the United States" (17 FPC 385–389) which terms and conditions, designated as Articles 1 through 17, are attached hereto and made a part hereof, except for the last sentence of Article 11; and subject to the following special conditions set forth herein as additional articles:

Article 18. The Licensee shall pay to the United States the following annual charge, effective as of August 1, 1945:

For the purpose of reimbursing the United States for the costs of administration of Part I of the Act one (1) cent per horsepower on the authorized installed capacity (20,000 horsepower) plus two and one-half (2½) cents per 1,000 kilowatt-hours of gross energy generated during the calendar year for which the charge is made.

Article 19. The Licensee shall for the protection of navigation, construct, maintain, and operate at its own expense such lights and other signals on fixed project structures in or over navigable waters of the United States as may be directed by the Secretary of the Department in which the Coast Guard is operating.

Article 20. The Licensee shall construct, maintain, and operate, or shall arrange for the construction, maintenance, and operation of artificial propagation facilities and such other permanent fish facilities and protective devices and shall comply with such reasonable modifications of the project structures and operation in the interest of fish and wildlife resources, provided, that such

modifications shall be reasonably consistent with the primary purpose of the project and not unduly impair the power value of the project, as may be prescribed hereafter by the Commission upon its own motion or upon the recommendation of the Secretary of the Interior or the New Hampshire Fish and Game Department, after notice and opportunity for hearing and upon a finding based on substantial evidence that such modifications are necessary and desirable, and consistent with the provisions of the Act.

Article 21. Whenever the United States shall desire, in connection with the project, to construct fish handling facilities or to improve the existing fish handling facilities at its expense, the Licensee shall permit the United States or its designated agency to use, free of cost, such of Licensee's lands and interests in lands, reservoirs, waterways and project works as may be reasonably required to complete such fish handling facilities or such improvements thereof. In addition, after notice and opportunity for hearing the Licensee shall modify the project operation as may be prescribed by the Commission, consistent with the primary purpose of the project, in order to permit the maintenance and operation of the fish handling facilities constructed or improved by the United States under the provision of this article. This article shall not be interpreted to place any obligation on the United States to construct or improve fish handling facilities or to relieve the Licensee of any obligation under this license.

Article 22. The Licensee shall install additional capacity and make other changes in the project as directed by the Commission, to the extent that it is economically sound and in the public interest to do so, after notice and opportunity for hearing.

Article 23. The Licensee shall, after notice and opportunity for hearing, coordinate the operation of the project with such other power systems as the Commission may direct in the interest of power and other beneficial public uses of water resources, the benefits of which shall be shared equitably by the participants in such coordination.

(C) The exhibits designated and described in finding (2) above are approved as part of this license.

(D) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313(a) of the Act, and failure to file such an application shall constitute acceptance of this license. In acknowledgement of the acceptance of this license, it shall be signed for the Licensee and returned to the Commission within 60 days from the date of issuance of this order.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE, PROJECT NO. 2288

OPINION AND ORDER ISSUING LICENSE

(Issued April 25, 1962)*

Syllabus

1. Appropriate license term for projects constructed prior to 1935 amendments to Federal Power Act and operated thereafter in navigable waters without requisite federal authorization is 50 years from 1943, *i.e.*, December 31, 1993. P. 832.
2. Licenses for projects constructed subsequent to 1935 amendments to the Act should be made effective not later than date of construction of such projects. P. 832.

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*Designated Commission's Opinion No. 357. Modified by order issued February 14, 1964, 31 FPC 417.

3. License from Federal Power Commission for an unlicensed project occupying navigable stream became mandatory upon adoption of Section 23(b) in 1935. P. 833.
4. A company whose project has enjoyed three or more decades of unregulated operation would reap a substantial windfall from its prolonged delay in filing were it granted a full 50 year license term from date of issuance. P. 833.
5. To extent feasible it is duty of sound licensing to minimize inequities. P. 833.
6. Commission prescribes license term commencing in 1943, for reason concept of navigability attained its present dimension then—citing *City of Spooner, Wisconsin*, *Wisconsin Michigan Power Company*, and *Wisconsin Public Service Corporation*. P. 833.
7. Commission exercises its discretion in making license effective as of July 1, 1958. P. 834.
8. In future cases (not involving prior finding of navigability, unauthorized construction subsequent to 1935, or other unusual circumstances), policy will be to tender licenses effective as of beginning of month present order is issued, *i.e.*, April 1, 1962, Commission concluding that to make future licenses effective as of date of issuance might encourage further delay in filing license application. P. 834.
9. In deciding not to impose retrospective charges for period prior to July 1, 1958, Commission gives some weight to possibility that to do so might deter potential applicants from complying with statute, should experience indicate such applicants are not voluntarily complying, Commission may wish to reconsider its policy on back dating. P. 834.
10. Commission *rejects* conclusion that a river does not become "navigable" or license necessary until Commission or some other authority so rules; *holds* Section 23 flatly proscribes the unlicensed operation of power project in "navigable waters," and Section 3(8) defining "navigable waters" is addressed directly to project owners no less than Commission. P. 835.
11. Effect of present order is to abandon premises enunciated in *Carolina Aluminum* and return to what Commission conceives to be sounder principles of *Metropolitan Edison*. P. 835.
12. Applicant had no right to rely on Commission finding prior to 1943, as to non-navigability of Androscoggin River, once narrow jurisdictional criteria formerly employed had been superseded. P. 836.
13. Replacement of one timber cribbed dam for another does not warrant the grant of 50 year license term from date of partial reconstruction; it would be anomalous to establish later termination date merely because applicant failed to comply with statute. P. 836.
14. Commission declines to anticipate approach it will take with license application embracing proposed as well as existing project works; present ruling as to termination and effective date is not to be followed mechanically in all cases involving pre-1935 projects on streams used for logging. P. 836
15. Commission *issues* license under Section 4(e) of the Federal Power Act; effective July 1, 1958, and terminating December 31, 1993. P. 838.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

Ross, *Commissioner*

On December 27, 1960, Public Service Company of New Hampshire (Applicant) filed application for a license under Section 4(e) of the Federal Power Act (hereinafter referred to as "the Act") for its constructed Project No. 2288, known as the Gorham Project, located on the Androscoggin River in the town

of Gorham, Coos County, New Hampshire. The application recites that the first generating plant and original dam at the Gorham site were constructed in 1894. The dam was rebuilt in 1903, 1927, and 1928. Two 400 kw generating units were installed in 1917 and the turbines replaced in 1937. Two 675 kw generating units were installed in 1923. The three sections of the powerhouse were constructed in 1909, 1917 and 1923, respectively, and have remained substantially unchanged since 1923. These early installations and changes were made by predecessors of Applicant, which acquired the facilities on December 12, 1943. In 1958 and 1959, Applicant removed the old timber-cribbed dam and built a new one, also timber-cribbed.

In its order issued July 24, 1958,[1] the Commission found that the Androscoggin River throughout its entire length is a "navigable water" as defined in Section 3(8) of the Federal Power Act and a "navigable water of the United States" within the meaning of Section 23(b) of the Act. The basis for this finding was that the Androscoggin is presently, and for more than a century has been, used for the transportation of logs and other forest products by water.

This application raises again a question which has perplexed the Commission for many years, *i.e.*, the appropriate license term to be accorded a project constructed prior to the 1935 amendments to the Act[2] and operated thereafter in navigable waters without requisite federal authorization. The resolution of this question calls for the exercise of sound discretion, for while Section 6 of the Act fixes a 50 year ceiling on license terms, it evidently contemplated that the Commission may prescribe a shorter period if circumstances so warrant. After evaluating all relevant factors, we propose to issue Applicant a license effective as of July 1, 1958, and terminating December 31, 1993. Since the reasons which lead us to prescribe the above license term will also guide the action we shall take upon pending and future applications involving other pre-1935 projects, it is important that those reasons be fully explained.

Section 23(b) of the Act declares it unlawful to construct, *operate*, or *maintain* hydroelectric works in navigable waters of the United States except under an FPC license or appropriate pre-1920 federal permit. This provision, one of several amendments enacted as part of the Public Utilities Act of 1935,[3] was intended as a concise restatement of a prohibition deemed by the draftsmen to be embodied already in Section 9 of the River and Harbor Act of 1899, when read together with Section 4(d) of the Federal Water Power Act of 1920.[4] While the relationship between the 1899 and 1920 statutes was not explicitly defined in

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[1] New Hampshire Water Resources Board, Docket No. E-6807, 20 FPC 99-101.

[2] The construction of any project works *subsequent* to the enactment of Section 23(b) of the Act of 1935 without the concurrent filing of a license application or declaration of intention plainly violates that section. There is little room for dispute that licenses for such projects should be made effective not later than the date of construction of such project works.

[3] By Title II of the Public Utility Act of 1935, the original Federal Water Power Act of 1920, 41 Stat. 1063, was made Part I of the Federal Power Act and Parts II and III were added.

[4] H. Rep. No. 1318, House Comm. on Interstate and Foreign Commerce 26, 74th Cong., 1st Sess. (1935); S. Rep. No. 2796, Senate Comm. on Interstate and Foreign Commerce 47, 74th Cong., 1st Sess. (1935).

Section 9 of the River and Harbor Act of 1899, 33 U.S.C. § 401, declared it unlawful to construct certain kinds of structures, including dams, over any navigable water of the United States without the consent of Congress and the approval of plans by the Chief of Engineers and the Secretary of War. Section 4(d) of the Federal Water Power Act, 41 Stat. 1065, the forerunner of the present Section 4(e) of the Federal Power Act, authorized the Commission to issue licenses for hydroelectric project works situated on navigable waters of the United States, provided that no license affecting navigable capacity should be issued until plans for the contemplated structures had been approved by the Chief of Engineers and the Secretary of War.

either act, any uncertainty there might have been as to the legal status of an unlicensed power project occupying a navigable stream vanished with the adoption of Section 23(b) in 1935. From that point on, if not earlier, a license from this Commission was clearly mandatory. Unfortunately, the Commission has lacked sufficient funds or man power to enforce general compliance with the statute, and as a result a large number of projects, including the one involved in this application, have continued to operate without licenses. If a company whose project has enjoyed three or more decades of unregulated operation were granted a full 50-year license term from date of issuance, it would reap a substantial windfall from its prolonged delay in filing. Equally important, it would obtain an unmerited advantage over those companies which complied at an earlier date, inasmuch as projects of the latter will be subject to federal recapture well within the next 50 years. To the extent feasible, it is the burden of a sound licensing policy to minimize such inequities.

The above considerations might well justify the issuance of a license effective as of August 26, 1935 (or even earlier), and terminating August 26, 1985, as well as the imposition of annual charges for that entire period. We are persuaded, however, to allow for the fact that the concept of navigability has evolved only gradually and did not attain its present dimensions until 1943. Prior to that date, it might have been reasonable for a company to assume that the Commission would not assert jurisdiction over a project situated in a stream in which virtually the sole traffic had been the driving of logs. From 1920 to 1930, the Commission disclaimed jurisdiction in a majority of the cases in which declarations of intention were submitted to it. In 22 instances, rivers—many of which, including the Androscoggin, have subsequently been determined navigable—were found not to be navigable at project site even though they were known to have been used for the transportation of forest products. During that period the Commission apparently employed an extremely pragmatic criterion, namely, whether or not any actual or probable navigation was in fact likely to be endangered by the proposed hydroelectric project. From 1931 until 1942, the Commission accepted jurisdiction in 14 of the 39 declaration-of-intention cases which it acted upon but in only one such case made a finding of navigability at site. In 1940, the Supreme Court held in *United States* v. *Appalachian Power Co.*, 311 U.S. 377, that a stretch of river may be navigable in law even though improvements may be necessary to make it so in fact. While the *Appalachian* case was a major landmark in the development of the Commission's jurisdiction, it did not deal with a river which had been used chiefly for logging operations. In 1943, however, three Commission decisions based findings of navigability primarily upon evidence of log driving and rafting.[5] One of these decisions, involving the Tomahawk project on the Wisconsin River, was affirmed in 1945 by the Court of Appeals for the Seventh Circuit,[6] which concluded (at 147 F. 2d 748) that

> * * * the evidence as shown by this record, establishes a long, regular and commercially successful use of the stream for the transportation of logs and rafts, and forms a reasonable basis in law for the conclusion that the Wisconsin River was and is a navigable water of the United States.

At least as early as the 1943 decisions, the owner of every project located in a stream capable of being used for the transportation of logs was placed on notice

[5] *City of Spooner, Wisconsin*, 3 FPC 986 (April 20, 1943); *Wisconsin Michigan Power Company*, 3 FPC 449 (July 27, 1943); *Wisconsin Public Service Corporation* (Tomahawk), 3 FPC 495 (July 30, 1943).

[6] *Wisconsin Public Service Corporation* v. *F.P.C.*, 147 F. 2d 743 (7th Cir. 1945), *cert. den.*, 325 U.S. 880.

of the perils of further unlicensed operation. Such perils must have been particularly apparent to the present Applicant, for logging has been a continuing and conspicuous activity on the Androscoggin down to the present day. For the reasons stated, it is in our view appropriate that the license tendered herein be for a term ending December 31, 1993.

The same reasoning which commends the adoption of December 31, 1993, as a termination date would also warrant us in making the license effective as of January 1, 1944. Were we to do so, Applicant would be liable for annual charges commencing on such effective date and would be required as of January 1, 1964, to establish the amortization reserves provided for in Section 10(d) of the Act. While such retrospective treatment would be a legitimate exercise of our discretion, we are satisfied that under present circumstances the advancement of the termination date in the manner above described gives adequate weight of the unlicensed history of the Gorham project prior to July 1, 1958. Our discretion, however, should not be so exercised as to ignore either of the more flagrant breaches of statutory duty committed by Applicant in 1958 when it (a) failed to apply for a license even after our determination of jurisdiction over the Androscoggin in Docket No. E–6807; and (b) replaced its dam without filing either a license application or a declaration of intention, one or the other of which submission was required by Section 23(b) whether the Androscoggin was navigable or not. In the latter connection, it should be pointed out that if Applicant, subsequent to 1935, had built an entirely new project without securing the requisite authorization, we would not hesitate to adopt the date of such construction as the effective date of its license. We see no reason for different treatment merely because the unauthorized construction took the form of a replacement of an existing facility. Since the application now before us does not indicate the precise date upon which the construction was commenced, we are content to make the license effective as of July 1, 1958, the first day of the month in which we determined jurisdiction in Docket No. E–6807. In future cases which do not involve a prior finding of navigability as to the subject river, an unauthorized construction subsequent to 1935 or other unusual circumstances (e.g., the incurrence by the Commission of substantial administrative, investigative, or litigative expenses directly attributable to the applicant's recalcitrance) our policy will be to tender licenses effective as of the beginning of the month in which the present order is issued, *i.e.*, April 1, 1962. Our reason for not making future licenses effective as of the date of their issuance is that to do so might encourage still further delay in filing the license applications which the law requires.

In deciding not to impose retrospective charges for the period prior to July 1, 1958, we have given some weight to the possibility that imposition of such charges might seriously deter potential applicants from coming forward to comply with the statute. If, however, our experience during the next twelve months indicates that voluntary cooperation will in any event not be forthcoming, we may well wish to reconsider the position we now take on the question of backdating.

In prescribing a license term which takes into account the prior unlicensed operation of the project, we revive a policy repeatedly employed by the Commission from 1942 until 1957. During that period it was the Commission's practice to issue licenses effective as of January 1, 1938, and terminating either on June 30, 1970, the fiftieth anniversary of the adoption of the Federal Water Power Act of 1920,[7] or, in the case of projects constructed later than 1920, 50 years from the date of such construction. January 1, 1938, was utilized as the effective date, from which annual charges were computed, in order that each

[7] The Federal Water Power Act was approved on June 10, 1920, 41 Stat. 1063.

licensee might bear its fair share of the expenses incurred by the Commission in connection with a general investigation of unlicensed projects which it had initiated by order of December 23, 1937. The basis for the prescribed termination dates was spelled out in the following passage from the Commission's opinion in *Metropolitan Edison Company*, 6 FPC 189 (1947) (at 191–192):

> The applicant also requests that the license cover a longer period than merely to June 30, 1970, as prescribed in the order of November 7, 1944. Except in cases where an earlier date is appropriate, June 30, 1970, is the termination date prescribed by the Commission since 1938 in all licenses for constructed projects operating without prior Federal authority. The York Haven plant was first placed in operation in 1904 and a license should have been obtained as early as 1920 when the original Power Act became law. The obligation to obtain a license rests upon the owner of each hydroelectric project operating without appropriate Federal authority in streams subject to the jurisdiction of Congress. If a company could willfully violate the law and fail to obtain a license for 26 years as this applicant has done, and then receive a 50-year license from the date on which it filed the application, its license would run for 26 years more than if it had obtained the requisite authority in 1920. To grant this request of the applicant would be to accord it a special privilege not accorded to companies which applied for appropriate authority at an earlier date and not contemplated by the Congress in the statute limiting the license period to 50 years. Hence in this, as in other similar cases, the Commission has limited the term to June 30, 1970, and the request should be refused.

While the specific termination and effective dates previously utilized by the Commission are no longer desirable, and while, as mentioned earlier, we do not find it necessary to decide whether a license should have been obtained as early as 1920, we do subscribe to the basic reasoning set forth in the paragraph quoted above.

In *Carolina Aluminum Company*, Project No. 2197, and *Carolina Power and Light Company*, Project No. 2206, 19 FPC 704, consolidated cases decided in 1958, the Commission discarded its long established backdating policy and repudiated the logic of *Metropolitan Edison*. The position it took is that the Act does not require any company to apply for a license until such time as an authoritative determination has been made that the stream in which the company operates is navigable. Pursuant to this view, the Commission adopted a policy of issuing 50 year licenses effective as of the date on which its jurisdiction over the river in question was determined.[8] We find no basis, however, either in the language of the Act or its legislative history, for the conclusion that a river does not become "navigable," or a license necessary, until the Commission or some other authority has so ruled. On the contrary, Section 23(b) flatly proscribes the unlicensed operation of a power project in "navigable waters," and Section 3(8), which defines "navigable waters," is addressed directly to the project owners no less than to the Commission. The effect of our present order is to abandon the premises enunciated in the *Carolina Aluminum* case and to return to what we conceive to be the sounder principles of *Metropolitan Edison*.

Reference should be made to two aspects of the present application which might perhaps be thought to except it from the general rules discussed above. First, the Androscoggin River, as noted earlier, was one of several streams originally determined by the Commission to be non-navigable despite its use for logging purposes. It could be argued that by virtue of this determination,

[8] See, *e.g.*, *Duke Power Company*, Project No. 2232, 20 FPC 360 (September 17, 1958); *Marathon Corporation*, Project No. 2212 (April 28, 1959) (unreported); *Wisconsin Valley*

made in 1925 in response to a declaration of intention by the Dummer Power Company,[9] it was not unlawful for Applicant and its predecessors to operate the Gorham project without a license prior to the Commission's 1958 redetermination of the status of the river. We cannot accept that proposition. After 1943, the navigable character of the Androscoggin under then prevailing standards was no less obvious than that of other rivers which were similarly used for logging, but for which no prior determination had been made. Once it became clear that the narrow jurisdictional criteria formerly employed by the Commission had been superseded, Applicant had no greater right to rely upon the Dummer decision than upon any of the other decisions rendered on the basis of the outmoded criteria of the 1920's.[10]

The second noteworthy feature is that in 1958 and 1959, Applicant removed its old dam and built a new one. The contention might be made that, having invested additional funds in the Gorham project, Applicant should be granted a 50 year license term from the date of this partial reconstruction. In a case where construction results in the replacement of substantially all existing facilities and the material enlargement of the scale of the project, there might conceivably be some basis for prescribing a license term ending 50 years from the date of such improvements. The replacement of one timber-cribbed dam by another, however, does not warrant such treatment. Had the Gorham project already been under license as to the commencement of new construction, we would amend the license to include the new dam, not issue a new 50 year license for the entire project. It would be anomalous to establish a later termination date merely because Applicant had failed to comply with the statute.

While the license term prescribed in the instant case will serve as a model for future Commission action, it should not be viewed as a rigid formula to be followed mechanically in all cases involving pre-1935 projects on streams used for logging. There may well be circumstances in which the adoption of December 31, 1993, as a termination date or April 1, 1962, as an effective date would be unwise or inappropriate. Specifically, we decline to anticipate the approach we will take when presented with a license application embracing proposed as well as existing project works.

The Secretary of the Army and the Chief of Engineers have approved the plans of the project structures insofar as the interests of navigation are concerned.

An Assistant Secretary of the Interior, in reporting on the application, recommended for inclusion in any license issued certain conditions in the interests of fish life.

Improvement Company, Project No. 2113, 21 FPC 785 (May 28, 1959); *Tomahawk Power Company*, Project No. 2239, 22 FPC 1 (July 1, 1959); *Nekoosa-Edwards Paper Company*, Project No. 2255, 22 FPC 473 (September 1, 1959); *Consolidated Water Power Company*, Project No. 2256, 22 FPC 638 (October 5, 1959). This policy was foreshadowed by the Commission's decision in *Montana Power Company*, 15 FPC 1330 (April 23, 1956). That decision, however, which involved a proposed unit as well as existing structures, was based on the desirability of a uniform license term for all units of a single development rather than upon the doctrine expounded in *Carolina Aluminum*, and was not necessarily inconsistent with *Metropolitan Edison*.

[9] Fifth Annual Report of the Federal Power Commission, p. 57.

[10] We express no opinion as to how the matter might stand if Applicant, rather than the Dummer Power Company, had been the party which obtained the prior favorable determination. In the present case, at least, there is no question of collateral estoppel or *res judicata*.

The Commission finds:

(1) Applicant is a corporation organized under the laws of the State of New Hampshire and has submitted satisfactory evidence of compliance with the requirements of all applicable state laws insofar as necessary to effectuate the purposes of a license for the project.

(2) The project consists of:

(a) All lands constituting the project area and enclosed by the project boundary or the limits of which are otherwise defined, and/or interest in such lands necessary or appropriate for the purposes of the project, whether such lands or interest therein are owned or held by the licensee or by the United States; such project area and project boundary being more specifically shown and described by certain exhibits which formed part of the application for license and which are designated and described as follows:

Exhibit J: (FPC No. 2288–1) General Map of Project Area; and

Exhibit K: (FPC Nos. 2288–2 and –3) Detail Map of Project Area.

(b) Project works consisting of:

An L-shaped dam comprised of three sections, (1) a rock-filled timbercrib section faced with steel piling and normally surmounted by flashboards, (2) a rock-filled timbercrib section faced with wood planking and normally surmounted by hinged wood flashboards and (3) a concrete gravity section normally surmounted with flashboards and including a gated log sluice-way; a reservoir with normal water surface at elevation 773.53 feet (USGS datum); a canal used as a forebay extending to the powerhouse intake section; a powerhouse containing two 583 horsepower turbines connected to 400-kilowatt generators and two 1,000-horsepower turbines connected to 675-kilowatt generators; a 2.4 KV transmission line extending to the Gorham substation; remote control operating equipment; and appurtenant facilities; the location, nature, and character of which are more specifically shown and described by the exhibits hereinbefore cited and by certain other exhibits which also formed part of the application for license and which are designated and described as follows:

Exhibit L: General Design Drawings

FPC No.	Sheet No.	Description
2288–4	1	Plan of Dam.
2288–6	3	Dam—Plan of Timber Section.
2288–7	4	Dam—Sections of Timber Section.
2288–8	5	Generator Floor Plan—Unit No. 1 and 2.
2288–9	6	Powerhouse—Transverse and Longitudinal Sections—Unit No. 1 and 2.
2288–10	7	Generator Floor Plan—Unit No. 3 and 4.
2288–14	11	Powerhouse—Longitudinal Section.
2288–15	12	Powerhouse—Transverse Section.

Exhibit M: Sixteen typewritten pages, "General Description of Mechanical and Electrical Equipment," filed in the Commission December 27, 1960.

(c) All other structures, fixtures, equipment or facilities used or useful in the maintenance and operation of the project and located on the project area, including such portable property as may be used or useful in connection with the project or any part thereof, whether located on or off the project area, if and to the extent that the inclusion of such property as a part of the project is approved or acquiesced in by the Commission; also, all riparian or other rights, the use

or possession of which is necessary or appropriate in the maintenance and operation of the project.

(3) No conflicting application is before the Commission. Public notice of the filing of the application has been given as required by the Act. No protests have been received.

(4) The issuance of a license as hereinafter provided will not affect a Government dam or the development of any water resources for public purposes which should be undertaken by the United States.

(5) Subject to the terms and conditions hereinafter imposed, the project is best adapted to a comprehensive plan for improving and developing the Androscoggin River for the use or benefit of interstate or foreign commerce, for the improvement and utilization of water-power development, and for other beneficial public uses, including recreational purposes.

(6) The following described transmission and electrical facilities are parts of the project within the meaning of Section 3 (11) of the Act and should be included in the license for the project as hereinafter provided:

(a) the 2.4 KV line to the Gorham substation.

(b) the 2.4/33 KV transformers in the Gorham substation.

(c) the 2.4 KV switching facilities.

(d) switching facilities necessary to connect the 2.4/33 KV transformers to the 33 KV bus at the Gorham substation.

(7) The installed horsepower capacity of the project hereinafter authorized for the purpose of computing the capacity component of the administrative annual charge is 2,900 horsepower.

(8) The amount of annual charges to be paid under the license for the purpose of reimbursing the United States for the costs of administration of Part I of the Act is reasonable as hereinafter fixed and specified.

(9) The energy generated by the constructed project is distributed and sold by Applicant for public utility purposes.

(10) The exhibits designated and described in finding (2) above conform to the Commission's rules and regulations and should be approved as part of the license for the project as hereinafter provided.

The Commission orders:

(A) This license is issued to Public Service Company of New Hampshire under Section 4(e) of the Act for a period effective July 1, 1958, and terminating December 31, 1993, for the continued operation and maintenance of the Gorham Project No. 2288, located on the Androscoggin River, a navigable water of the United States, in the town of Gorham, Coos County, State of New Hampshire, subject to the terms and conditions of the Act which is incorporated herein by reference as a part of this license, and subject to such rules and regulations as the Commission has issued or prescribed under the provisions of the Act.

(B) This license is also subject to the terms and conditions set forth in Form L–3, December 15, 1953, entitled "Terms and Conditions of License for Constructed Major Project Affecting Navigable Waters of the United States" (17 FPC 385–389) which terms and conditions, designated as Articles 1 through 17, are attached hereto and made a part hereof, except for the last sentence of Article 11; and subject to the following special conditions set forth herein as additional articles:

Article 18. The Licensee shall pay to the United States the following annual charges, effective as of July 1, 1958:

For the purpose of reimbursing the United States for the costs of administration of Part I of the Act one (1) cent per horsepower on the authorized installed capacity (2,900 horsepower) plus two and one-half (2½) cents per 1,000 kilowatthours of gross energy generated during the calendar year for which the charge is made.

Article 19. The Licensee shall for the protection of navigation, construct, maintain and operate at its own expense such lights and other signals on fixed structures in or over navigable waters of the United States as may be directed by the Secretary of the Department in which the Coast Guard is operating.

Article 20. The Licensee shall construct, maintain, and operate, or shall arrange for the construction, maintenance, and operation of artificial propagation facilities and such other permanent fish facilities and protective devices and shall comply with such reasonable modifications of the project structures and operation in the interest of fish and wildlife resources, provided, that such modifications shall be reasonably consistent with the primary purpose of the project and not unduly impair the power value of the project, as may be prescribed hereafter by the Commission upon its own motion or upon the recommendation of the Secretary of the Interior or the New Hampshire Fish and Game Department, after notice and opportunity for hearing and upon a finding based on substantial evidence that such modifications are necessary and desirable, and consistent with the provisions of the Act.

Article 21. Whenever the United States shall desire, in connection with the project, to construct fish handling facilities or to improve the existing fish handling facilities at its expense, the Licensee shall permit the United States or its designated agency to use, free of cost, such of Licensee's lands and interests in lands, reservoirs, waterways and project works as may be reasonably required to complete such fish handling facilities or such improvements thereof. In addition, after notice and opportunity for hearing the Licensee shall modify the project operation as may be prescribed by the Commission, consistent with the primary purpose of the project, in order to permit the maintenance and operation of the fish handling facilities constructed or improved by the United States under the provision of this article. This article shall not be interpreted to place any obligation on the United States to construct or improve fish handling facilities or to relieve the Licensee of any obligation under this license.

Article 22. The Licensee shall install additional capacity and make other changes in the project as directed by the Commission, to the extent that it is economically sound and in the public interest to do so, after notice and opportunity for hearing.

Article 23. The Licensee shall, after notice and opportunity for hearing, coordinate the operation of the project with such other power systems as the Commission may direct in the interest of power and other beneficial public uses of water resources, the benefits of which shall be shared equitably by the participants in such coordination.

(C) The exhibits designated and described in finding (2) above are approved as part of this license.

(D) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313(a) of the Act, and failure to file such an application shall constitute acceptance of this license. In acknowledgment of the acceptance of this license, it shall be signed for the Licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

COLUMBIA GULF TRANSMISSION COMPANY; KENTUCKY GAS TRANSMISSION CORPORATION; UNITED FUEL GAS COMPANY, DOCKET NO. CP62-56

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued April 26, 1962)

On August 31, 1961, as supplemented on September 6, 1961, and October 27, 1961, Columbia Gulf Transmission Company (Columbia Gulf) and Kentucky Gas Transmission Corporation (Kentucky Gas) filed in Docket No. CP62-56 a joint application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of an interconnection between their pipelines in Madison County, Kentucky, and the delivery of natural gas through said interconnection by Columbia Gulf to Kentucky Gas in the event of an emergency on the latter's system. On January 18, 1962, United Fuel Gas Company (United Fuel) filed an amendment to the subject application and joined as an applicant herein. The proposed construction, operations, and sale are more fully set forth in the application, as supplemented and amended.

Applicants' proposed emergency connection will be made between Columbia Gulf's 30-inch main line and Kentucky Gas' 8-inch KA-1 pipeline at a point in Madison County, Kentucky. The KA-1 is an isolated line not connected to Kentucky Gas' main transmission system. The gas supply for this line is obtained solely from Tennessee Gas Transmission Company at a point near Richmond, Kentucky, which gas is delivered for the account of United Fuel Gas Company. Through Line KA-1 Kentucky Gas provides wholesale service to the City of Richmond, Kentucky, to Columbia Gas of Kentucky, Inc., and to Petroleum Exploration, Inc., all for resale in various Kentucky communities.

To insure continuous and interrupted service to Kentucky Gas' utility customers (served from Line KA-1) in the event of a break on, or loss of supply to that line, Applicants propose to establish the emergency interconnection. Any emergency deliveries to Kentucky Gas by Columbia Gulf would be made for the account of United Fuel, the latter being the only customer of Columbia Gulf and one of the suppliers to Kentucky Gas. United Fuel has requested Columbia Gulf to make the proposed connection and joins in the request for certificate authorization to establish the new delivery point to Kentucky Gas. There will be no new sale arising from the use of the proposed emergency connection. The proposed facilities will permit delivery of up to approximately 25,000 Mcf per day by Columbia Gulf to Kentucky Gas.

The total cost of the proposed facilities is estimated to be $28,300. Columbia Gulf proposes to construct and operate a 6-inch main line tap and a side gate valve on its line at an estimated cost of $4,400. Kentucky Gas proposes to construct a main line tap on its 8-inch line, a side gate, and a measuring and regulating station at an estimated cost of $23,900. United Fuel will not build anything nor bear any of the costs.

Pursuant to due notice, a public hearing was held in Washington, D.C., on April 17, 1762, respecting the matters involved in and the issues presented by the application, as supplemented and amended, herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure

be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Columbia Gulf Transmission Company, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the National Gas Act as heretofore found by the Commission in its order of November 5, 1958, in Docket No. G–15524 (20 FPC 681).

(2) Applicant, Kentucky Gas Transmission Corporation, a Delaware corporation having a principal place of business in Charleston, West Virginia, is a "natural-gas company" within the means of the National Gas Act as heretofore found by the Commission in its order of August 10, 1956, in Docket No. G–9689 (16 FPC 437).

(3) Applicant, United Fuel Gas Company, a West Virginia corporation having its principal place of business in Charleston, West Virginia, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of March 1, 1944, in Docket No. G–341 (4 FPC 534).

(4) The facilities hereinbefore described, as more fully described in the application, as supplemented and amended, in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicants are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) Applicants are able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(6) The construction and operation of facilities and the delivery of natural gas as proposed by Applicants are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicants, Columbia Gulf Transmission Company, Kentucky Gas Transmission Corporation, and United Fuel Gas Company, to construct and operate the facilities hereinbefore described, and to deliver natural gas through said facilities on an emergency basis, all as more fully set forth in the application as supplemented and amended, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The time within which the subject facilities shall be completed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act is hereby fixed at 5 months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

KENTUCKY WEST VIRGINIA GAS COMPANY, DOCKET NO. CP62-163

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, PERMITTING AND APPROVING ABANDONMENT AND ACCEPTING RATE FILING

(Issued April 26, 1962)

On January 9, 1962, Kentucky West Virginia Gas Company (Applicant) filed in Docket No. CP62-163 an application pursuant to Section 7 of the Natural Gas Act for a certificate of public convenience and necessity authorizing certain additional delivery points for its previously authorized exchange of natural gas with Inland Gas Company, Inc. (Inland), and for permission and approval to abandon certain delivery points in connection with the said exchange of gas with Inland.

In Docket No. G-272, Applicant was authorized to make deliveries of natural gas to Inland at certain points in Kentucky according to the terms of a letter agreement between Applicant and Inland. Applicant states that the agreement was amended from time to time and on October 9, 1950, the agreement was restated in the form that now appears in Applicant's FPC Gas Tariff, Original Volume No. 2, First Revised Sheet Nos. 7, 8, and 9. Applicant states further that since October 1950, there have been occasions when it was desirable to eliminate certain of the delivery points and at times to add others. The subject application seeks authorization for such additions and eliminations. These delivery point modifications have been embodied in an agreement, dated October 5, 1961, between Applicant and Inland.

The delivery points proposed to be abandoned and the reasons therefor are:

(1) *Johnson County* point, Johnson County, Kentucky. The gas delivered by Applicant at this point had a high sulfide content and Applicant had to pay 4 cents per Mcf to Inland to purify it. A decrease in gas available at this point, and a breakdown in Inland's purification plant resulted in the elimination of this delivery.

(2) *Lackey* point, Floyd County, Kentucky. Lackey was established as a balancing point, but very little gas was ever delivered from it by Applicant. Increased supplies of gas available to Inland from other sources eliminated the need for this delivery point.

(3) *Mousie* point, Knott County, Kentucky. The delivery pressure on Inland's gas system became greater than the pressure that was available from Applicant's facilities at the Mousie delivery point and it was therefore eliminated.

The following are the additional delivery points provided for in the agreement of October 5, 1961, for which Applicant herein seeks authorization:

(1) *Nelson Allen* delivery point, Magoffin County, Kentucky. Established by letter agreement, dated June 22, 1953, and restated in agreement, dated October 5, 1961.

(2) *Camp Branch*, Rockhouse Creek delivery point, Knott County, Kentucky. Established by letter agreement, dated April 2, 1956, and restated in agreement, dated October 5, 1961.

(3) *Abbott Creek*, Myrtle delivery point, Magoffin County, Kentucky. Established by letter agreement, dated October 9, 1953, modified by letter agreement, dated September 17, 1954, and restated in agreement, dated October 5, 1961.

(4) *Oakley Creek*, Magoffin County delivery point, Magoffin County, Kentucky. Subject of application in Docket No. CP61-343.

On January 12, 1962, Applicant filed the letter agreement, dated October 5, 1961, as Second Revised Sheet Nos. 6, 7, 8, and 9, and Original Sheet No. 9-A to its FPC Gas Tariff, Original Volume No. 2.

Pursuant to due notice, a public hearing was held in Washington, D.C., on April 16, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Kentucky West Virginia Gas Company, a West Virginia corporation having its principal place of business in Ashland, Kentucky, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of January 4, 1944, in Docket No. G-272 (4 FPC 476).

(2) The additional delivery points hereinbefore described, as more fully described in the application in this proceeding, are to be used in the exchange and delivery of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation of such delivery points by applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) The additional delivery points proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(4) The delivery points to be abandoned, as hereinbefore described, are subject to the jurisdiction of the Commission, and abandonment of such delivery points is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(5) Such abandonment by Applicant, as hereinbefore described, is permitted by the public convenience and necessity, and an order authorizing and approving same should be issued as herinafter ordered.

(6) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(8) The letter agreement, dated October 5, 1961, and filed on January 12, 1962, should be accepted for filing as Second Revised Sheet Nos. 6, 7, 8 and 9, and Original Sheet No. 9-A to Applicant's FPC Gas Tariff, Original Volume No. 2, to become effective on the day this order issues.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Kentucky West Virginia Gas Company, to establish the additional delivery points for the exchange and delivery of natural gas, as hereinbefore described, all as more fully described in the application herein, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) Permission for and approval of the abandonment by Applicant of the delivery points hereinbefore described, all as more fully described in the application in this proceeding, be and the same is hereby granted.

(D) The letter agreement, dated October 5, 1961, and filed on January 12, 1962, is hereby accepted for filing as Second Revised Sheet Nos. 6, 7, 8, and 9, and Original Sheet No. 9–A to Applicant's FPC Gas Tariff, Original Volume No. 2 to become effective on the day this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

MONTANA-DAKOTA UTILITIES CO., DOCKET NO. E–7027

ORDER AUTHORIZING THE ISSUANCE OF PROMISSORY NOTES

(Issued April 26, 1962)

Montana-Dakota Utilities Co. (Applicant), incorporated under the laws of the State of Delaware and doing business in the States of Minnesota, Montana, North Dakota, South Dakota, and Wyoming, with its principal business office at Minneapolis, Minnesota, filed an application on March 12, 1962, as supplemented on April 12 and 20, 1962, for authority, pursuant to Section 204 of the Federal Power Act, to issue unsecured Promissory Notes in the aggregate principal amount of $12,000,000, outstanding at any one time. Each of the proposed Notes will be dated as of the dates of their respective issue, which will be not later than December 31, 1962; will mature not more than one year after their respective dates of issue and not later than December 31, 1963; and, will bear interest at the prime commercial bank rate in effect in New York City at the time of each borrowing.

Applicant proposes to issue the Notes to the First National City Bank of New York. Through separate agreements between this bank and the Northwestern National Bank of Minneapolis and the First National Bank of Minneapolis, the two Minneapolis banks will each have a 25% participation in each note. The application indicates that none of the Notes proposed to be issued will be resold to the general public and no finder's fee or other negotiation fee, commission or remuneration will be paid in connection therewith to any third person.

Applicant states that the proceeds to be obtained from the proposed issuance of Notes will be used to provide temporary financing for part of the cost of Applicant's 1962 construction program, estimated at $18,000,000, which is approximately equally divided between additions to Applicant's electric facilities and additions to Applicant's gas facilities. The principal item in the electrical program is $6,000,000 for the 66,000 kw generating unit addition to the R. M.

Heskett station near Mandan, North Dakota, scheduled to be completed in late 1963 at a total cost of $10,425,000. The principal items in Applicant's gas program are: $4,425,000 for 106 miles of twelve inch natural gas pipeline between Minot and Bismarck, North Dakota, with laterals to and distribution systems in six contiguous communities; $715,000 for 29 miles of six and four inch pipeline between Williston and Watford City, North Dakota; and $1,382,000 for 26 miles of twelve inch pipeline loop between the Little Beaver, Montana, and Belle Fourche, South Dakota, compressor plants and one 880 hp compressor unit at each plant. Applications for certification of the gas items are now pending before this Commission in Docket Nos. CP61-234, CP61-297, and CP62-225, respectively. Applicant states that none of the proposed Notes will be issued to obtain funds for the payment of the cost of construction of the afore-mentioned gas facilities prior to the issuance of certificates of convenience and necessity in accordance with the Natural Gas Act. The application indicates that Applicant expects to issue First Mortgage Bonds in the fall of 1962 to discharge all short-term Notes then outstanding.

Written notice of the application has been given to the Minnesota Railroad and Warehouse Commission, the Montana Board of Railroad Commissioners, the North Dakota Public Service Commission, the South Dakota Public Utilities Commission, and the Wyoming Public Service Commission, and to the Governor of each of those States. Notice of the application was also published in the Federal Register on March 24, 1962 (27 F.R. 2780), stating that any person desiring to be heard or to make any protest with reference to said application should file a petition or protest, on or before April 9, 1962, with the Federal Power Commission, Washington 25, D.C. No protest, petition or request to be heard in opposition to the granting of the application has been received.

The Commission finds:

(1) Applicant, a Delaware corporation, owns and operates facilities, among others, which are used for the transmission and sale at wholesale of electric energy which is transmitted between the States of Montana and North Dakota, between the States of North Dakota and South Dakota, and from the State of Montana to the State of Wyoming, all of which facilities are in addition to, and do not include, facilities used for the generation of electric energy or facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or facilities for the transmission of electricity consumed wholly by the transmitter. Applicant is, therefore, a public utility within the meaning of that term as used in Section 204 of the Federal Power Act.

(2) The proposed issuance of Promissory Notes, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204(f) of the Act; and the proposed issuance of Promissory Notes, as described above, is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance of Promissory Notes in the aggregate principal amount of $12,000,000, all as described above, will be in excess of 5% of the par value of the other securities of Applicant, and, therefore, will not be exempt by virtue of Section 204(e) of the Act from the requirements of Section 204(a) of the Act.

(5) The proposed issuance of Promissory Notes, described above, will be exempt from the competitive bidding requirements of Section 34.1a of the Commission's Regulations under the Federal Power Act by reason of Paragraph 34.1a(a)(2) thereof.

(6) The proposed issuance of Promissory Notes, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility, and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The proposed issuance of Promissory Notes by the Applicant, in an aggregate principal amount of not to exceed $12,000,000 at any one time outstanding, upon the terms and conditions and for the purposes set forth in the application, is hereby authorized, subject to the provisions of this order.

(B) The authorization is expressed conditioned upon the final maturity of all Notes to be issued pursuant thereto, being not later than December 31, 1963.

(C) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuations, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(D) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States in respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

THE SUPERIOR OIL COMPANY, DOCKET NOS. G–15554, G–15555, G–15648, G–16335

ORDER DENYING REHEARING

(Issued April 26, 1962)

On April 3, 1962, Superior Oil Company (Superior) filed application in the above dockets for rehearing of the Commission's omnibus order of March 5, 1962 in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, 27 FPC 441.* By that order we disposed of more than 400 proceedings, including those above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. In Docket Nos. G–15554, G–15555, and G–15648, with respect to rate schedules applicable to sales to Transcontinental Gas Pipe Line Corporation (Transco) and Texas Gas Transmission Corporation (Texas Gas), the effect of the March 5 order was to reinstate the Commission's order of February 21, 1961, in which Superior was required to refund tax-reimbursement amounts without regard to whether it had obtained corresponding tax refunds from the State of Louisiana. In Docket No. G–16335, involving sales to Trunkline Gas Company, the March 5 order in effect reinstated the Commission's order of May 29, 1961, which limited the refund obligation to amounts actually received by Superior from the State of Louisiana.

Superior's application recites that Superior paid the tax under protest and thus obtained a refund from the State of Louisiana; that in compliance with the Commission's order of February 21, 1961, Superior paid to each of its purchasers the amounts required to be refunded and secured from each purchaser

*Superior styled its filing a "Motion for Rehearing." We deem it, however, an application for rehearing within the meaning of Section 19(a) of the Natural Gas Act.

release of all claims with respect to the invalidated tax; that on July 5, 1961, Superior filed with the Commission a report of compliance, submitted release agreements for each sale subject to suspension under its dockets and requested that the Commission enter an order discharging Superior from all further refund obligations.

Superior assumes that the order of March 5 imposes a refund obligation additional to and different from that imposed by the February 21, 1961, order, with which it claims to have complied. On the basis of that assumption it requests that the ordering paragraphs of the March 5 order be modified so as to except the above dockets or, in lieu thereof, that the Commission enter an order discharging Superior from all further liability. In fact, however, the March 5 order was intended merely to revive the obligation originally imposed by the February 21, 1961, order but later abated (as to producers who received no tax refund) by the order of May 29. It will be observed that the operative language of ordering paragraph (A) of the March 5 order is substantially the same as that of ordering paragraph (A) of the February 21, 1961, order, both requiring refunds of "amounts collected under the respective agreements and undertakings filed in compliance with the Commission's [suspension] orders." Moreover, Superior must report to the Commission as required by ordering paragraph (C) of the March 5 order only "if it has not already done so." It is clear that if Superior has complied in full with the requirements of the February 21, 1961, order, as it alleges, it will *ipso facto* have complied with the order of March 5, 1962. To allay any uncertainties which may be troubling Superior, the Commission's Secretary will advise the company by letter whether it has satisfactorily demonstrated its compliance with the refund obligation imposed by the February 21, 1961, order and revived by the order of March 5.

In light of the foregoing discussion, we see no reason to modify the March 5 order or to grant Superior's application for rehearing.

The Commission finds:

Superior's application for rehearing of the Commission's order of March 5, 1962, should be denied.

The Commission orders:

Superior's application for rehearing of the Commission's order of March 5, 1962, is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

TEXACO INC., *ET AL.*,* DOCKET NOS. G–15546, *ET AL.*;* ARKANSAS LOUISIANA GAS COMPANY, *ET AL.*, ** DOCKET NOS. G–16125, *ET AL.*

ORDER DENYING APPLICATIONS FOR REHEARING AND GRANTING EXTENSION OF TIME

(Issued April 26, 1962)

By companion orders issued March 5, 1962, in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, and *Arkansas Louisiana Gas Company, et al.*, Docket Nos.

*As noted in Appendix A hereof under columns entitled "Docket Nos." and "Applicants." [Appendix A omitted in printing.]

**The Docket Nos. hereby designated are *Tennessee Gas Transmission Company*, G–15567; *Olin Gas Transmission Corporation*, G–15695; *Mississippi River Fuel Corporation*, G–15880; and *Mississippi River Fuel Corporation*, G–16468. In each of these dockets the applicant for rehearing is Southern Natural Gas Company, the purchaser.

G–16125, *et al.*, 27 FPC 441 and 437, respectively,[1] the Commission disposed of more than 400 proceedings, including those listed above, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. In certain of these proceedings, the March 5 order[2] directed producers to refund tax-reimbursement amounts collected from Transcontinental Gas Pipeline Corporation (Transco), Texas Gas Transmission Corporation (Texas Gas), and United Fuel Gas Company (United Fuel). In the remaining dockets, the Commission declined to order refunds on the ground that the purchasers by neglecting to file timely petitions for intervention or applications for rehearing of the order of May 29, 1961, 25 FPC 1058,[3] had allowed their rights to expire. Timely applications for rehearing of the March 5 order have been filed in the above dockets by producers who were ordered to make refunds and by direct and secondary purchases to whom refunds were denied.

In support of their applications, the producers advance various contentions to the effect that under Section 19 of the Natural Gas Act the Commission lacked jurisdiction to reconsider or disturb the finality of the May 29 order. In addition, some argue that they were deprived of the trial-type hearing allegedly required by the Administrative Procedure Act, the Natural Gas Act, and the Commission's regulations. Finally they challenge the merits of our decision to order refunds, urging among other things, that the 1958 suspension orders, construed in the light of contemporaneous certificate orders and letters from the Commission to the Louisiana Collector of Revenue, did not impose a refund obligation upon producers who elected not to protest the tax; that there were valid business reasons for declining to pay under protest; that the Commission erred in assuming that producers could protest the tax without being forced to initiate litigation; and that the Commission ignored the possibility that the refunded amounts might constitute a windfall to the pipelines.

With regard to the finality of the May 29 order and the adequacy of the hearing procedure, substantially all of the contentions set forth in the applications were considered by the Commission in its prior deliberations and were answered either in its order of March 5 or its order of April 13 denying an application for rehearing filed in certain proceedings by Pan American Petroleum Corporation.[4] One point, however, merits further comment. Several of the producers urge that since the May 29 order was itself issued upon reconsideration of a prior order, it was immune to further reconsideration by the Commission. As authority for this view they rely upon *Trunkline Gas Company et al.*, Docket Nos. G–15394, *et al.*, 21 FPC 394 (1959), and *Houston, Texas Gas and Oil Corporation*, Docket No. G–9262, 17 FPC 542 (1957). Neither of the cited cases, however, is apposite. In *Trunkline*, the Public Service Commission of New York (PSC) applied for rehearing of an order denying it intervention. The Commission granted rehearing, but later declined on the merits to accord PSC the requested status of an intervener. When PSC filed a second application for rehearing, substantially identical in aim and content with its first, the Commission ruled it out of order. In *Houston*, the Commission's Secretary rejected the tender of an application for rehearing addressed to an order which

[1] The *Texaco* order pertained to sales of gas by independent producers to pipeline companies; the *Arkansas Louisiana* order pertained to field sales by pipeline companies.

[2] The term "March 5 order," as used herein, shall refer to the order issued in Docket Nos. G–15546, *et al.*

[3] By that order, the Commission limited the producers' refund obligation to amounts recovered by the producers from the State of Louisiana.

[4] The dockets in which Pan American sought rehearing were Nos. G–15641, G–15650, G–15780, G–16065, G–16066, and G–16067.

itself had denied a similar application filed by the same party. Thus, the principle for which these cases stand is that where the Commission has responded negatively to an application for rehearing, either by denying the application itself or by deciding against the applicant upon reconsideration of the merits, the disappointed party's proper recourse is to petition for judicial review, not to importune the Commission with a further application. That principle, however, has no bearing upon the present proceedings, since the applications for rehearing of the May 29 order were the only ones to be filed by the three purchasers involved. Moreover, inasmuch as none of these purchasers was aggrieved by the order of February 21, 1961, it is difficult to see how they *could* properly have sought rehearing at any earlier stage. The only real question, therefore, is whether the attempt by Texas Gas to intervene in the proceedings subsequent to May 29 was still timely.[5] On this point we adhere to the conclusion expressed in our March 5 order. It should be emphasized that until April 14, 1961, when the Commission granted applications for rehearing filed by producers in thirteen of the sixty-one dockets involving sales to Texas Gas,[6] there was no reason to suspect that the producers' refund obligation would even be disputed. It might, perhaps, have been prudent for Texas Gas to seek intervention immediately thereafter in those proceedings which had been reopened by the April 14 order. However, in view of the fact that the Commission did not issue its customary notice fixing a time for intervention, invite statements of position, or otherwise establish procedures for litigating the refund issue, we do not believe that Texas Gas should be deemed to have forfeited its right to make its voice heard in these proceedings merely because it did not come forward prior to May 29.

On the merits of the refund question, the Union Oil Company of California (Union), one of the producer applicants, raises the only consideration not dealt with in our March 5 order. Union charges the Commission with having ignored the settled principle of restitution that a buyer can recover from his seller the amount of an invalid tax included as a separable component of the purchase price only if (i) the seller has been reimbursed by the taxing authorities and (ii) the refund will not unjustly enrich the buyer. As to the first of these two conditions, it must be noted that in the cases relied upon by Union the only noncontractual basis upon which the sellers' refund obligation could be predicated was that of unjust enrichment. In the instant proceedings, however, the producers' refund obligation is derived from suspension orders issued by this Commission in furtherance of its regulatory objectives under the Natural Gas Act. The purpose of the suspension orders was not merely to prevent the unjust enrichment of the producers, but also and primarily to insure that the customers would not be forced to pay a rate which included the amount of an invalid tax. Admittedly, if there had been no way by which the producers could have recouped from the State of Louisiana the amounts required to be refunded to their customers, we would have a different question. Procedures for obtaining a tax refund did exist, however, and the fact that some of the producers elected not to avail themselves of these procedures, and thus cannot at this late date be made whole, is not a sufficient reason to inflict upon their customers the burden of an invalid and readily avoidable tax.

The second branch of Union's argument is that the Commission, in considering the equities, failed to take into account the possibility that the refunds

[5] Transco had sought intervention, and United Fuel had been admitted as an intervener, prior to the May 29 order.

[6] The dockets referred to are those which are included both in Appendix B and Appendix E of the March 5 order.

might be a windfall to the recipient pipelines. The fact is, however, that before issuing the March 5 order, the Commission took steps to verify that its action would not yield a windfall. The records of the Commission confirm representations made by Transco in these proceedings to the effect that the increased costs attributable to the gathering tax were never passed on in the form of higher rates. Having absorbed the tax, Transco will not be unjustly enriched if it is allowed to retain the amounts refunded to it pursuant to our March 5 order. In Docket No. G–16316, United Fuel filed for a rate increase reflecting the increase in its tax-reimbursement obligations triggered by the Louisiana tax. The Commission permitted the rate to become effective subject to refund, as of September 23, 1958. Thus, the portion of the tax allocable to the period August 1, 1958, to September 23, 1958, was absorbed by the company. By order of September 15, 1960, in Docket No. G–16316,[7] the Commission approved a settlement agreement, the effect of which will be to require United Fuel to pass on to its wholesale customers their proportionate share of any refunds received by United Fuel under the March 5, 1962 order. In Docket No. G–16405, Texas Gas increased its rates, effective October 1, 1958, to cover its additional tax-reimbursement expenses. The costs allocable to the preceding two-month period were absorbed by the company. By order issued October 30, 1959, the Commission approved termination of the above docket on condition that Texas Gas refund to each of its customers whose rates were increased, the applicable portion of any refunds received by Texas Gas from its suppliers in the event that the gathering tax should be held invalid. In light of the above circumstances, it is clear that none of the pipelines entitled the above refunds in accordance with the March 5 order will be unjustly enriched thereby.

The contention chiefly relied upon by the purchasers in their applications is that the March 5 order, insofar as it denied to some purchasers the relief it granted to others, was inconsistent with the approach adopted in the May 29, 1961, order, which was applied uniformly to all dockets, not merely those in which the producers had sought rehearing of the February 21, 1961, order. It is our view, however, that the *sua sponte* action involved in the May 29 order was significantly different in character from that which would now be required were we to grant refunds in all dockets. The avowed purpose of our earlier order was to qualify the producers' refund obligation in conformity with what was stated to be the Commission's subjective intent at the time it issued its original suspension orders, as well as the order of February 21, 1961. The modification of the February 21 order can thus be viewed as an effort to rectify the omission of an intended provision. As such it falls within a category of *sua sponte* action which the Supreme Court has held to be proper.[8] A *sua sponte* order directing refunds to all purchasers could not be similarly justified.

Other arguments, too numerous for meaningful treatment herein, are contained in the purchasers' applications. All such arguments have been considered by the Commission and found to be without merit.

The application for rehearing filed by producer Sun Oil Company (Sun) is accompanied by an application to stay the effectiveness of ordering paragraphs (A), (B), and (C) of the March 5 order for a period of sixty days after final Commission action on Sun's application for rehearing and until final disposition of any petition for judicial review. Sun advises that in Docket Nos. G–15632 and G–15768, involving sales to Transco, it has already filed a petition for review

[7] United Fuel Gas Company, 24 FPC 467 (1960).

[8] *American Trucking Associations, Inc.* v. *Frisco Transportation Company,* 358 U.S. 133 (1958).

of the March 5 order in the Court of Appeals for the District of Columbia Circuit. For reasons stated in our order of April 13, 1962,[9] granting Pan American Petroleum Corporation an extension of time for compliance, we propose to extend the time within which Sun must comply with ordering paragraphs (A) and (C) of the Commission's March 5 order, for a period ending 30 days after conclusion of judicial review of that order in Docket Nos. G–15632, G–15633, G–15743, and G–15768. The extension is conditional, however, upon the payment by Sun to its customers Transco, United Fuel, and Texas Gas of interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the order of March 5.

The Commission finds:

(1) The applications filed in the instant dockets for rehearing of the Commission's order of March 5, 1962, should be denied.

(2) There is good cause for extending the time within which Sun must comply with the requirements of ordering paragraphs (A) and (C) of our order of March 5, 1962, for a period ending 30 days after conclusion of judicial review of that order in Docket Nos. G–15632, G–15633, G–15743, and G–15768, respectively.

(3) It is just and reasonable and in the public interest that Sun be required to pay its customers Transco, United Fuel, and Texas Gas interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after the issuance of our March 5 order.

The Commission orders:

(A) The applications filed in the instant dockets for rehearing of the Commission's order of March 5, 1962, are hereby denied.

(B) The time within which Sun must comply with ordering paragraphs (A) and (C) of the Commission's order of March 5, 1962, insofar as applicable to Docket Nos. G–15632, G–15633, G–15743, and G–15768, respectively, is extended for a period ending 30 days after conclusion of judicial review of that order in each of those respective dockets.

(C) Sun shall pay Transco, United Fuel, and Texas Gas interest, at a rate of 7% upon the amounts to be refunded, for the period commencing on the 91st day after issuance of the March 5, 1962, order.

(D) The time within which Transco, United Fuel, and Texas Gas must comply with ordering paragraphs (B) and (D) of the March 5, 1962, order, insofar as applicable to Docket Nos. G–15632, G–15633, G–15743, and G–15768, respectively, is extended for a period ending 60 days after the conclusion of judicial review of that order in each of those respective dockets.

(E) The preceding paragraphs (B) through (D) hereof shall not be deemed operative with respect to Docket Nos. G–15633 and G–15743 unless and until Sun shall have filed a petition for review therein. Thus, if within 90 days after the issuance of the March 5 order, Sun shall neither have complied with ordering paragraphs (A) and (C) thereof nor petitioned for review, it shall be deemed in default. In the event that Sun's pending petition for review in Docket Nos. G–15632 and G–15768 are dismissed on grounds of prematurity and that no further petitions for review are filed therein within the time limit prescribed by Section 19(b) of the Natural Gas Act, the preceding paragraphs (B) through (D) hereof shall be deemed inoperative and of no effect.

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[9] *Pan American Petroleum Corporation*, Docket No. G–15641; *Pan American Petroleum Corporation (Operator), et al.*, Docket Nos. G–15650, G–15780.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

OLIN GAS TRANSMISSION CORPORATION, DOCKET NO. CP62-125; JOSEPH E. SEAGRAM & SONS, INC., d.b.a. FRANKFORT OIL COMPANY, DOCKET NO. CI62-370

FINDING AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND ACCEPTING RATE SCHEDULE FOR FILING

(Issued April 27, 1962)

On November 20, 1961, Olin Gas Transmission Corporation (Olin) and on October 9, 1961, Joseph E. Seagram & Sons, Inc., d.b.a. Frankfort Oil Company (Frankfort), filed in Docket Nos. CP62-125 and CI62-370, respectively, applications pursuant to Section 7(c) of the Natural Gas Act for certificates of public convenience and necessity authorizing the sale of natural gas to Texas Eastern Transmission Corporation (Texas Eastern) from their respective interests in the North Gillis Field, Calcasieu Parish, Louisiana.

The proposed sale by Frankfort will be made pursuant to a contract dated March 21, 1961, between Frankfort and Texas Eastern. Olin has adopted and ratified said contract between Frankfort and Texas Eastern, and the proposed sale by Olin will be made pursuant thereto.

The sale of natural gas will be made at a proposed total initial price of 15.8007 cents per Mcf at 15.025 psia.

Concurrently with the filing of its application herein, Olin filed the gas purchase contract dated March 21, 1961, as its proposed FPC Gas Rate Schedule F-12.

By letter, dated October 24, 1961, Frankfort was granted temporary authorization to commence the subject sale of natural gas.

Pursuant to due notice, a public hearing was held in Washington, D.C., on April 19, 1962, respecting the matters involved in and the issues presented by the applications herein. No petition to intervene or protest to the granting of the applications has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practices and Procedure.

The Commission finds:

(1) Applicant, Olin Gas Transmission Corporation, a Delaware corporation having its principal place of business in New Orleans, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of April 30, 1954, in Docket No. G-2335 (13 FPC 1012).

(2) Applicant, Joseph E. Seagram & Sons, Inc., d.b.a. Frankfort Oil Company, an independent producer of natural gas, is engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption subject to the jurisdiction of the Commission, and is, therefore, a "natural-gas company" within the meaning of the Natural Gas Act.

(3) The sales of natural gas hereinbefore described, as more fully described in the applications in this proceeding, will be made in interstate commerce subject to the jurisdiction of the Commission, and such sales by the Applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) Applicants are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(5) The sales of natural gas by Applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity, and certificates therefor should be issued as hereinafter ordered and conditioned.

(6) The gas purchase contract, dated March 21, 1961, filed by Olin concurrently with its application in Docket No. CP62–125, should be accepted for filing as Olin's FPC Gas Rate Schedule F–12 to become effective on the date this order issues.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Certificates of public convenience and necessity be and the same are hereby issued, upon the terms and conditions of this order, authorizing the sales by Applicants, Olin and Frankfort, of natural gas to Texas Eastern in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary for such sales, as hereinbefore described, all as more fully described in the respective applications in this proceeding.

(B) The certificates granted in paragraph (A) above are not transferable and shall be effective only so long as Applicants continue the operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations, and orders of the Commission.

(C) The grant of the certificates issued in paragraph (A) above shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or Part 154 or Part 157 of the Commission's Regulations thereunder, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Applicants. Further, our action in this proceeding shall not foreclose or prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contract herein involved.

(D) The gas purchase contract, dated March 21, 1961, filed by Olin concurrently with its application in Docket No. CP62–125, is hereby accepted for filing as Olin's FPC Gas Rate Schedule F–12 to become effective on the date this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodard.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. CP62–103

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued April 27, 1962)

On October 20, 1961, as supplemented on October 26, 1961, November 1, 1961, and January 24, 1962, Transcontinental Gas Pipe Line Corporation (Applicant)

filed in Docket No. CP62-103 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction during a 12-month period and the operation of field booster compressor facilities and appurtenant equipment to enable Applicant to take into its certificated pipeline system volumes of natural gas which may be purchased in presently connected fields, at a total cost not to exceed $1,000,000 with no single installation to exceed a cost of $250,000, all as more fully set forth in the application, as supplemented.

In a number of fields connected to Applicant's system declining wellhead pressures are diminishing the volumes of gas which would otherwise be deliverable to Applicant by contract, thus necessitating the installation of the facilities for which authorization is sought herein.

No new sale or service is proposed in the application. The construction and operation of the subject facilities will not increase the delivery capacity of Applicant's main transmission system.

The proposed facilities will be financed from cash on hand or, alternatively, by short term bank loans.

The facts relevant to the need for additional compression are:

Field and County (Texas)

	South Karon and Coquat Field, Live Oak County	Goebel Field, Live Oak County	St. Charles Field, Aransas County	Kittiewest Field, Live Oak County	Arneckville Field, Dewitt County		South Pleasanton Field, Atascosa County
Reserves available to Applicant as of January 1, 1961	5,696,000 Mcf	5,139,000 Mcf	40,286,000 Mcf	1,728,000 Mcf	13,681,000 Mcf		8,436,000 Mcf.
Seller and FPC Gas Rate Schedule Number	Western Natural Gas Company, R.S. 7.	Western Natural Gas Company, R.S. 7.	Western Natural Gas Company, R.S. 7. Continental Oil Company, R.S. 105.	Western Natural Gas Company, R.S. 7.	Atlantic Refining Company, R.S. 42.	Western Natural Gas Company, R.S. 7.	Robert Mosbacher (Operator), *et al.*, R.S. 16.
Average price in ¢/Mcf (including tax reimbursement)	8.921227¢	8.921227¢	8.921227¢	8.921227¢	8.890883¢	8.890883¢	14.189¢
Incremental compression	1.639¢	1.639¢	1.639¢	1.639¢	1.29¢	1.29¢	1.46¢
Total cost (¢/Mcf)	10.560227¢	10.560227¢	10.560227¢	10.560227¢	10.180883¢	10.180883¢	15.649

On December 11, 1961, Applicant was granted temporary authorization to construct and operate the proposed facilities in the Arneckville and South Pleasanton Fields on the condition that the independent producers involved file changes in their respective related rate schedules to reflect the lower delivery pressures to Applicant.

Installation of compressors in other fields may become necessary during the period for which authorization is hereinafter granted.

Pursuant to due notice, a public hearing was held in Washington, D.C., on April 17, 1962, respecting the matters involved in and the issues presented by the Application, as supplemented, herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c) (1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Transcontinental Gas Pipe Line Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 28, 1950, in Docket No. G–1277 (9 FPC 32).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing pipeline system, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction for a 12-month period and the operation of field booster compressor facilities to take natural gas from producers thereof in presently connected fields as proposed by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, not more than 60 days following the expiration of the authorization hereinafter granted, a statement under oath showing by installation: (a) names of fields in which facilities are installed, (b) a description of the facilities installed pursuant to the authorization hereinafter granted, (c) the costs of the facilities so constructed, and (d) the names of the independent producers (other than those mentioned herein) from whom gas is purchased through said facilities.

(6) The authorization hereinafter granted should be limited to construction for a 12-month period following the date on which the order issues, and the total expenditures for facilities to be constructed thereunder should be limited to $1,000,000, with no single installation to exceed a cost of $250,000.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas

Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(8) The authorization hereinafter granted should be subject to the condition that Robert Mosbacher (Operator) *et al.*, Atlantic Refining Company, Western Natural Gas Company, and Continental Oil Company file changes in their respective related rate schedules to reflect the changes in service, i.e., delivery of gas at lower pressures to Applicant; and further, if compression facilities are installed to receive gas from other producers under the authorization hereinafter granted, said authorization should be conditioned upon the filing by said producers of changes in their respective related rate schedules to reflect the changes in service, i.e., delivery of gas at lower pressures to Applicant.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Transcontinental Gas Pipe Line Corporation to construct during the 12-month period commencing on the date on which this order issues the proposed facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, and to operate such facilities only to take natural gas supplies in presently connected fields purchased from producers who have received authorization from the Commission to sell natural gas to Transcontinental Gas Pipe Line Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(C) Applicant shall submit, not more than 60 days following the expiration of the authorization granted in paragraph (A) above, a statement under oath showing by installation: (a) names of fields in which facilities are installed, (b) a description of said facilities, (c) costs of the facilities so constructed, and (d) names of the independent producers (other than those mentioned herein) from whom gas is purchased through said facilities.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the 12-month period commencing with the date on which this order issues, and the total expenditures for facilities to be constructed hereunder are hereby limited to $1,000,000 with no single project to exceed a cost of $250,000.

(E) The authorization granted in paragraph (A) above is subject to the condition that Robert Mosbacher (Operator) *et al.*, Atlantic Refining Company, Western Natural Gas Company, and Continental Oil Company file changes in their respective related rate schedules to reflect the changes in service, i.e., delivery of gas at lower pressures to Applicant; and further, if compression facilities are installed to receive gas from other producers under the authorization hereinbefore granted, said authorization shall be conditioned upon the filing by said producers of changes in their respective related rate schedules to reflect the changes in service, i.e., delivery of gas at lower pressures to Applicant.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. CP62-143

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND ACCEPTING RATE SCHEDULE FOR FILING

(Issued April 27, 1962)

On December 8, 1961, Transcontinental Gas Pipe Line Corporation (Applicant) filed in Docket No. CP62-143 an application pursuant to Section 7 of the Natural Gas Act for a certificate of public convenience and necessity authorizing an additional 421 Mcf per day of storage service to Elizabethtown Consolidated Gas Company (Elizabethtown) an existing customer.

Applicant states that it will provide the proposed additional volumes from the unallocated portion of its share of the Leidy Storage Field. The proposed storage service will be rendered initially under Applicant's presently effective LS Rate Schedule.

Presently Elizabethtown has 6,000 Mcf of natural gas per day allocated to it from the Leidy Field. The proposed additional volumes will be utilized by Elizabethtown to assist it in minimizing the high costs associated with peak shaving.

No additional facilities will be required to render the proposed service.

Elizabethtown will provide gas for injection into Leidy Field from its present allocations for future withdrawal of the additional 421 Mcf per day.

Concurrently the filing of the application herein, Applicant filed a proposed service agreement, dated December 4, 1961. Said service agreement is for a term of one year from the date the additional proposed service commences. Applicant states that it expects such agreement to be superseded by a new long-term agreement reflecting the additional service.

Pursuant to due notice, a public hearing was held in Washington, D.C., on April 19, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Transcontinental Gas Pipe Line Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of November 18, 1948, in Docket No. G-1143 (7 FPC 139).

(2) The additional natural gas storage service for Elizabethtown as hereinbefore described and as more fully described in the application herein will be made in interstate commerce, subject to the jurisdiction of the Commission, and such additional service by Applicant is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The additional service of natural gas hereinbefore described is required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter to Applicant and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (c)(3), and (e) of Section 157.20 of such Regulations.

(6) The service agreement dated December 4, 1961, filed by Applicant concurrently with its application herein, should be accepted for filing to become effective on the date on which this order issues.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been defined by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Transcontinental Gas Pipe Line Corporation, to render additional natural gas storage service for Elizabethtown as hereinbefore described, all as more fully described in the Application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (c)(3), and (e) of Section 157.20 of such Regulations.

(C) The service agreement dated December 4, 1961, filed by Applicant concurrently with its application herein, is hereby accepted for filing to become effective on the date on which this order issues.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. CP61-194; NEW YORK STATE NATURAL GAS CORPORATION, CP61-198; TOWN OF LIBERTY, MISSISSIPPI, CP61-208; THE WIND GAP DIVISION OF BANGOR GAS COMPANY, CP61-222; THE HUGHESVILLE DIVISION OF JERSEY SHORE GAS & HEATING COMPANY, CP61-223; NEW YORK STATE NATURAL GAS CORPORATION, CP61-237; TEXAS EASTERN TRANSMISSION CORPORATION, CP61-238; NEW YORK STATE NATURAL GAS CORPORATION, CP61-238; TRANSCONTINENTAL GAS PIPE LINE CORPORATION, CP61-238.

ORDER ADOPTING WITH MODIFICATIONS THE INITIAL DECISION OF THE EXAMINER

(Issued April 27, 1962)*

Syllabus

1. Commission *issues* certificates of public convenience and necessity to applicants under Section 7 of the Natural Gas Act. P. 863.
2. Commission *directs* Transcontinental to establish physical connection of its transportation facilities with applicants proposed facilities and deliver and sell natural gas to applicant under Section 7(a) of the Natural Gas Act. P. 863.

James B. Henderson, William H. Davidson, William N. Bonner, Jr., Richard J. Connor, John T. Miller, Jr., George Grantham, and *Horace C. Wells* for Transcontinental Gas Pipe Line Corporation.

* Initial decision appears on p. 863.

G. Kirby Herrington, Richard B. Gordon, C. William Cooper, Lawrence L. Gray, George N. Reed, and *Thomas G. Roderick, Jr.,* for New York State Natural Gas Corporation.

Martin L. Friedman, Michael J. Shea, Keith M. Pyburn, and *Jack D. Head* for Texas Eastern Transmission Corporation.

John Ware III, J. David Mann, John E. Holtzinger, Jr., and *John N. Schaffer, Jr.,* for The Wind Gap Division of Bangor Gas Company; The Hughesville Division of Jersey Shore Gas & Heating Company; and Pittston Gas Company.

Hugh Connor and *John P. Sinclair* for Delaware Power & Light Company.

F. Kent Burns for North Carolina Utilities Commission.

Samuel G. Miller, Vincent P. McDevitt, and *Henry P. Sullivan* for the Philadelphia Electric Company.

Robert C. Koury for South Jersey Gas Company.

J. David Mann for Philadelphia Gas Works Division of the United Gas Improvement Company.

J. Harry Mulhern, Edward S. Kirby, and *William R. Duff* for Public Service Electric and Gas Company.

Armour T. Beckstrand, W. C. Braden, Jr., William W. Bedwell, Lambert McAllister, and *Francis J. Walsh* for Tennessee Gas Transmission Company.

John R. Sailer for Elizabethtown Consolidated Gas Company.

Herbert E. Squires, Alen R. Squires, Joseph I. Lewis, and *Martin Toscan Bennett* for Pennsylvania Public Utility Commission.

Frank P. Cooke for Public Service Company of North Carolina, Inc.

David K. Kadane, Edward M. Barrett, Bernard Hulkower for Long Island Lighting Company.

H. D. McHenry, William S. Traver, Hugh J. Morgan, Jr., for Southern Natural Gas Company.

Edwin F. Russell and *Harry G. Hill, Jr.,* for Brooklyn Union Gas Company.

William W. Ross and *J. David Mann* for Eastern Shore Natural Gas Company.

Kenneth Brim, Harry S. Littman, and *Dale A. Wright* for Piedmont Natural Gas Company, Inc.

James O'Malley, Jr., Halcyon G. Skinner, Ronald D. Jones, and *John A. Lodge* for Consolidated Edison Company of New York, Inc.

Brooks E. Smith and *Daniel L. Bell* for the Manufacturers Light and Heat Company, and Atlantic Seaboard Corporation.

Reuben Goldberg, George Spiegel, and *Charles E. Thomas* for Pennsylvania Gas and Water Company.

E. W. Moise and *Norman A. Flaningam* for Atlanta Gas Light Company.

John W. Kern, III and *Cecil A. Beasley, Jr.,* for City of Lexington, North Carolina.

Frank P. Cooke for Carolina Natural Gas Company.

R. H. Martin and *Raymond Dale Hodges* for the town of Liberty, Mississippi.

L. R. McClung for Water, Gas & Electric Department of the City of Danville, Virginia.

John Paul Geneau for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

These matters are before us upon exceptions filed by Commission Staff (Staff) on March 22, 1962, to the initial decision of the Presiding Examiner which was issued in said proceeding on March 2, 1962. No other exceptions have been filed. The decision disposes of the applications on the merits by granting the various authorizations sought. The Commission is in accord with, and affirms, such disposition.

Staff Exception No. 6, the only Staff exception taking issue with the Examiner's disposition as to the merits of any of the matters involved, objected to the grant of the application in Docket No. CP61–238 because of the failure of the Examiner to resolve a dispute between Staff and New York Natural over the interpretation of the evidence of record relating solely to certain aspects of the need for additional top storage capacity at the Leidy storage pool as proposed in said docket. This dispute no longer exists. As a result of a subsequent conference and agreement between Staff and New York Natural presented to the Commission on motion and answer by New York Natural and Staff, respectively, Staff withdrew its Exception No. 6 and requests approval of said withdrawal. This motion for withdrawal has been noted and is approved.

As indicated above, the remainder of Staff's exceptions do not run to the merits of any of the applications involved in this proceeding. These remaining exceptions concern the form of the order. These exceptions are granted. This requires a modification of the finding and ordering sections of the decision which are set forth at pages 36 to 40, inclusive, of said decision.

The Commission finds:

(1) Staff's withdrawal of its Exception No. 6 should be approved and the decision of the Examiner as to the merits of the matters involved should be affirmed as hereinafter ordered.

(2) Staff's remaining Exceptions should be granted as hereinafter ordered and the finding and ordering sections of the decision modified in accordance therewith by substituting the following finding and ordering clauses, as specifically designated, for clauses 5, 7–16 inclusive, (A) and (B) of said decision, to wit:

5. The facilities proposed to be constructed and operated by Transco in Docket No. CP61–194, including the interconnection required to sell and deliver additional volumes of gas to Penn Gas and the interconnection required to deliver authorized volumes of gas to Penn Gas in the event of the specified emergency, will be used for the transportation and sale of natural gas subject to the jurisdiction of the Commission as integral parts of Transco's existing natural gas pipeline system, and therefore, said facilities are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

7. The additional sales of natural gas, including those to Pittston and Penn Gas, and the storage services proposed to be made and rendered by Transco in Docket No. CP61–194 will be made in interstate commerce, subject to the jurisdiction of the Commission, and therefore, said sales and services are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

8. The operations, sale and storage service proposed to be rendered by New York Natural in Docket No. CP61–198 to Transco will be made in interstate commerce subject to the jurisdiction of the Commission, and therefore, said operations, sale and service are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

9. The development of the designated Greenlick gas field as an integral part of New York Natural's existing natural gas system for use as a natural gas storage pool, as proposed by New York Natural in Docket No. CP61–237, and the operation of said storage pool as a facility for the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

10. The further development and operation of additional underground storage capacity in the Leidy Pool and the construction and operation of facilities in connection therewith, as jointly proposed by New York Natural, Transco, and Texas Eastern in Docket No. CP61–238, for use in the transportation and sale

of natural gas in interstate commerce, subject to the jurisdiction of the Commission, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

11. The construction, operations, developments, sales and storage services referred to in Findings 5, 7, 8, 9, and 10 hereof are or will be required by the present or future public convenience and necessity, and therefore, the requests for certificates of public convenience and necessity in Docket No's. CP61–194, CP61–198, CP61–237, and CP61–238 should be granted and the applicants in said dockets authorized to perform the aforesaid acts, operations and services.

12. Public convenience and necessity require that the general terms and conditions set forth in paragraphs (a), (b), (c) (4), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.20) should attach to the certificates hereinafter issued in Docket No's. CP61–194, CP61–198, CP61–237, and CP61–238 and to the exercise of the rights granted thereunder, and that the time within which the facilities so authorized shall be constructed and placed in actual operation should be fixed at one year from the date on which this order shall become effective.

13. The Town of Liberty, Mississippi (CP61–208), a municipality, and The Wind Gap Division of Bangor Gas Company (CP61–222) and The Hughesville Division of Jersey Shore Gas & Heating Company (CP61–223), persons, are legally authorized, respectively, to engage in the local distribution of natural or artificial gas to the public.

14. It is necessary or desirable in the public interest that Transco be separately directed, pursuant to Section 7(a) of the Natural Gas Act, to:

(a) establish physical connection of its natural gas transportation facilities with the natural gas facilities proposed to be constructed and operated by The Town of Liberty, Mississippi (Liberty) in Docket No. CP61–208 and to sell and deliver up to a maximum volume of 531 Mcf per day of natural gas at 14.73 psia to Liberty for resale and distribution in Liberty, Mississippi, and environs including the community of Gillsburg as hereinbefore described in the application at Docket No. CP61–208, as amended, and on the record at the hearing and as hereinafter ordered and conditioned;

(b) establish physical connection of its natural gas transportation facilities with the natural gas facilities proposed to be constructed and operated by The Wind Gap Division of Bangor Gas Company (Wind Gap) in Docket No. CP61–222 and to sell and deliver up to maximum volume of 297 Mcf per day of natural gas at 14.73 psia to Wind Gap for resale and distribution in the Borough of Wind Gap and the Townships of Washington and Plainfield, Northampton County, Pennsylvania, as hereinbefore described in the application at Docket No. CP61–222, as amended, and on the record at the hearing and as hereinafter ordered and conditioned: *Provided further*, That Wind Gap demonstrates to the satisfaction of the Commission, within six months from the date of issuance of the Commission's order granting the instant application, that the Supradur Manufacturing Corporation has firmly committed itself to buy the estimated volumes of gas indicated in this proceeding; and

(c) establish physical connection of its natural gas transportation facilities with the natural gas facilities proposed to be constructed and operated by The Hughesville Division of Jersey Shore Gas & Heating Company (Hughesville) in Docket No. CP61–223 and to sell and deliver up to a maximum volume of 181 Mcf per day of natural gas at 14.73 psia to Hughesville for resale and distribution in the Borough of Hughesville, the Borough of Picture Rocks and in Wolf Township, Lycoming County, Pennsylvania, as hereinbefore described in

the application at Docket No. CP61–223, as amended, and on the record at the hearing and as hereinafter ordered and conditioned: *Provided further*, That Hughesville demonstrates to the satisfaction of the Commission, within six months from the date of issuance of the Commission's order granting the instant application, that the industrial customers involved have firmly committed themselves to buy the estimated volumes of gas indicated in this proceeding.

15. The ability of Transco to render adequate service to its existing customers will not be impaired and no undue burden will be placed upon Transco as a result of the directions contained in Finding 14 hereof.

16. Public convenience and necessity require that Transco shall report to the Commission, in writing and under oath, the dates of commencement of service to Liberty, Wind Gap, and Hughesville, respectively, within 30 days after the commencement of the respective service.

(A) Certificates of public convenience and necessity be and the same hereby are issued to Transco in Docket No. CP61–194, to New York Natural, in Docket Nos. CP61–198 and CP61–237, respectively, and to New York Natural, Transco, and Texas Eastern, jointly, in Docket No. CP61–238, respectively, authorizing the construction, operations, developments, sales and storage services referred to in Finding 11 hereof upon the conditions set forth in Finding 12 hereof and subject to all pertinent provisions of the Natural Gas Act and the Commission's regulations thereunder.

(B) Transco be and the same hereby is separately directed to establish physical connection of its natural gas transportation facilities with the natural gas facilities proposed to be constructed and operated by Liberty in Docket No. CP61–208, by Wind Gap in Docket No. CP61–222, and by Hughesville in Docket No. CP61–223, respectively, and to sell and deliver natural gas to Liberty, Wind Gap, and Hughesville, respectively, by means of said connections up to the volumes specified in, and in accordance with, Finding 14 hereof, and to report the commencement of each of said deliveries in accordance with Finding 16 hereof.

The Commission orders:

(A) The withdrawal of Staff Exception No. 6 is hereby approved and the decision of the Examiner upon the merits of the applications involved in this proceeding is hereby affirmed.

(B) The remaining Exceptions of Staff are hereby granted and the finding and ordering sections of the Examiner's decision are hereby modified as set forth in Finding (2) hereof.

DECISION

UPON APPLICATIONS PURSUANT TO SECTION 7(c) AND SECTION 7(a) OF THE NATURAL GAS ACT

(Issued March 2, 1962)

JENSCH, *Presiding Examiner:* Transcontinental Gas Pipe Line Corporation (Transco), a Delaware corporation, having its principal place of business in Houston, Texas, filed four separate applications seeking authority by the issuance of certificates of public convenience and necessity to render gas service in the manner more particularly later described herein and as fully set forth in the applications which were consolidated for purposes of hearing. In addition to Transco's request, there were consolidated for hearing the applications by two other pipelines, viz, Texas Eastern Transmission Corporation and New York State Natural Gas Corporation for authority to render service related to the initial proposals filed by Transco. Finally, there were also consolidated for

hearing certain Section 7(a) applications filed by certain existing and proposed gas distribution agencies seeking allocations of gas for their proposed service. At the conclusion of the hearings held [1] in these consolidated proceedings, requests were made for the submission of proposed findings and conclusions, in addition to briefs proposed to be filed, in an endeavor to expedite the consideration of the several issues involved herein, by an adoption thereof, if found consistent with the record of all of the evidence adduced herein. After due consideration of the said entire record, the proposed findings of fact reflected in the factual summary of the applications, and the facts developed at the hearing, submitted by the Staff, are accepted, and with some important modifications made to the proposed conclusions, the Staff proposals are substantially adopted and accepted and found consistent with and required by the public convenience and necessity, prescribed by the Natural Gas Act, as amended, and are adopted as the basis for this Decision.

On January 23, 1961, Transco filed an application in Docket No. CP61–194, as amended and supplemented on March 10, April 28, May 3, 5, and 8, and September 7, 1961, for a certificate of public convenience and necessity, pursuant to Section 7(c) of the Natural Gas Act, authorizing the construction and operation of additional transmission storage and sales facilities. The authorization requested by Transco is to increase long-term contract demand and general service to 26 of its existing customers by 99,290 Mcf per day at 14.7 psia and also to increase long-term storage service to 11 existing customers by 150,000 Mcf per day. The additional contract demand and general service [2] and half of the additional storage service [3] is needed as of December 1, 1961, while the remaining half of the storage service is needed as of 1962–63 heating season.

In support of Transco's proposed additional storage service, the following three additional applications were submitted.

On January 23, 1961, New York State Natural Gas Corporation (New York Natural), a subsidiary of Consolidated Natural Gas System, filed an application in Docket No. CP61–198, as amended on March 10 and March 27, 1961, for certificate authority to render natural gas storage service to Transco.[4] It would provide ultimately up to 150,000 Mcf per day and 7,500,000 Mcf annually for Transco as of 1962–63 heating season. All of New York Natural's general sys-

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[1] Pursuant to notice issued on July 19, 1961, a formal hearing in the above-captioned consolidated proceedings commenced on September 25, 1961. Thereafter, the hearing recessed on September 26, 1961, reconvened on October 24, 1961, and concluded on November 2, 1961. A motion to omit the intermediate decision procedure, made near the conclusion of the hearing, having been denied by order issued on November 8, 1961, provision for the filing of briefs was made. The last brief was filed December 22, 1961.

On February 15, 1962, notification was given by Tennessee of the requested withdrawal of all of its pleadings in this proceeding. This decision was in the final stages of preparation on February 15 and the withdrawal does not alter the results reached herein on the issues presented for consideration at the time of the hearing. No explanation was given for the withdrawal which was executed by a Vice President of the Company. Tennessee's position has been carefully analyzed since it filed its 98-page brief on December 8, 1961.

[2] Transco was granted temporary authorization on July 26, 1961, to construct a portion of the pipeline facilities and to operate the same for existing authorized service. On October 9, 1961, Transco was temporarily authorized to use the pipeline facilities for the proposed additional service.

[3] Transco was granted temporary authorization on June 26, 1961, to render only the 1961–62 storage service until May 1, 1962.

[4] On June 26, 1961, New York Natural was granted temporary authority to render storage service up to 75,000 Mcf per day for Transco only for the period ending May 1, 1962.

tem storage pools, both existing and proposed, would be used to render the proposed storage service.

On March 10, 1961, as amended May 2 and May 12, 1961, New York Natural filed an application in Docket No. CP61–237 for certificate authority to develop and operate existing properties and facilities for underground storage in the Greenlick pool,[5] which is located in northern Pennsylvania and which has an ultimate capacity of 53 billion cubic feet, when developed to its initial rock pressure. Only 5 billion cubic feet are to be injected initially (3 billion base and 2 billion top storage) with no additional facilities.

This additional underground storage development will be used by New York Natural to serve its existing customers and also to help it render the long-term storage service to Transco.

On March 10, 1961, as amended May 2, 1961, New York Natural, Texas Eastern, and Transco filed a joint application in Docket No. CP61–238, for authority to construct and operate certain facilities[6] in order to further develop and activate additional underground storage capacity in the Leidy storage pool, pursuant to Amendment No. 4, dated February 28, 1961, to the Leidy-Tamarack Transfer and Storage Agreement between the joint applicants.[7] The purpose of the 4th amendatory agreement is to provide 10,000,000 Mcf of top storage capacity in Leidy for New York Natural, which the latter company proposes to use in rendering the proposed storage service for Transco. The remaining additional underground storage capacity in the Leidy pool and the proposed capacity in the Greenlick project in Docket No. CP61–237 will enable New York Natural to take into its storage system commodity-cost gas which it has contracted to purchase and which it cannot utilize at the time, but which it can use later in winter, when needed, or when the cost of gas would be substantially higher.

The remaining applications and proposals involved in these proceedings are five in number and are set forth below. These requests were filed in conjunction with Transco's application in Docket No. CP61–194 and will be separately considered later herein.

Of these five proposals, three were filed as applications, pursuant to Section 7(a) of the Natural Gas Act, as follows:

Docket No. CP61–208—Town of Liberty, Mississippi.
Docket No. CP61–222—The Wind Gap Division of Bangor Gas Company.
Docket No. CP61–223—The Hughesville Division of Jersey Shore Gas & Heating Company.

The two remaining proposals consist of petitions for leave to intervene which are in the nature of applications under Section 7(a) of the Act. These two requests were filed by Pittston Gas Company and the Pennsylvania Gas and Water Company as heretofore noted.

The following table summarizes the temporary authorizations requested in the various dockets and the action taken by the Commission in each case:

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[5] On June 23, 1961, New York Natural was granted temporary authority to develop and operate the Greenlick pool.

[6] On June 26, 1961, New York Natural was granted temporary authorization to construct and operate only station piping to connect its Line No. 280 to the Leidy Compressor Station to help it render the 1961–62 storage service for Transco.

[7] Transco was granted temporary authorization on June 26, 1961, to provide up to 5,300,000 Mcf of base storage gas to inject in the Leidy storage pool. Texas Eastern received similar authorization on the same date. This was to enable the rendition of the 1961–62 storage service by Transco and New York Natural.

Docket No.	Temporary authorizations	Estimated cost	Commission action
CP61-194...	First—Construction and operation of south Louisiana offshore gathering facilities.	$1,959,006	Granted May 8, 1961.
	Second—To render the proposed 1961-62 additional storage service (75,000 Mcf per day).	None	Granted June 26, 1961.
	Third—To construct and operate (only for the existing authorized service) the loop line facilities and the new 4,000 horsepower compressor station and its related appurtenances initially applied for.	31,100,000	Granted July 26, 1961.
	Fourth—To construct and operate all the main line and the Leidy line compression facilities initially applied for.	7,025,000	Denied September 21, 1961.
	Fifth—To operate the facilities authorized in the third application for temporary authority to render the proposed additional pipeline services as well.	None	Granted October 9, 1961.
	Sixth—To construct and operate the additional main-line compressor horsepower of 13,400 to render presently authorized firm service in Zone 3 as of the Spring of 1962.	3,980,000	Pending.
CP61-238...	Transco to provide 5,300,000 Mcf of base storage gas for injection in the Leidy pool.	None	Granted June 26, 1961.
CP61-238...	Texas Eastern to provide 5,300,000 of base storage gas for injection in the Leidy pool.	None	Granted June 26, 1961.
CP61-238...	New York Natural to construct and operate station piping to connect its line No. 280 to the Leidy Compressor Station.	100,000	Granted June 26, 1961.
CP61-198...	New York Natural to render storage service of up to 75,000 Mcf per day for Transco only for the period ending May 1, 1962.	None	Granted June 26, 1961.
CP61-237...	New York Natural to develop and operate the Greenlick storage field for the proposed total storage capacity of 5 billion cubic feet.	None	Granted June 23, 1961.

Each of the several dockets is described in greater detail later herein. These consolidated proceedings included intervention by many gas distribution customer companies of the pipeline applicants. In addition, Southern Natural Gas Company and Tennessee Gas Transmission Company intervened in accordance with their contentions that their interests were affected by the applications filed by the other applicant pipeline companies. Atlantic Seaboard Corporation intervened only in connection with its allegation that its interests in the then pending Transco rate proceeding might be affected by the decision rendered in this proceeding. The following interventions were permitted by the Commission orders issued on June 28, 1961, August 8, 1961, September 21, 1961, and November 27, 1961.[8]

Tennessee Gas Transmission Company (Tennessee)
Southern Natural Gas Company (Southern)
Atlantic Seaboard Corporation (Seaboard)
Pittston Gas Company (Pittston)
Pennsylvania Gas and Water Company (Penn Gas)
Public Service Electric and Gas Company
Delaware Power & Light Company
Philadelphia Electric Company
South Jersey Gas Company
The United Gas Improvement Company
Elizabethtown Consolidated Gas Company
Public Service Company of North Carolina, Incorporated
Long Island Lighting Company
The Brooklyn Union Gas Company

[8] In addition, notices of intervention were filed by the North Carolina Utilities Commission and the Pennsylvania Public Utility Commission.

Eastern Shore Natural Gas Company
Piedmont Natural Gas Company, Inc.
The Manufacturers Light and Heat Company
Consolidated Edison Company of New York, Inc.
City of Lexington, North Carolina
Atlanta Gas Light Company
City of Danville, Virginia

All of the 21 interveners listed above, with the exception of Tennessee, Southern and Seaboard, are existing customers of Transco and seek additional service or volumes of gas from Transco in Docket No. CP61–194. The 18 customer interveners are either in support of Transco's application in Docket No. CP61–194 or are not opposed to the grant of said application or the other remaining applications. Of this group of 18 interveners, two, viz., Pittston and Penn Gas, fall into a special category in that their interventions are in the nature of Section 7(a) applications and, consequently are considered separately herein.

Southern's intervention is very limited in scope. It is concerned only with that part of Transco's application in Docket No. CP61–194 whereby Transco proposes to render additional service, viz, storage service and increased volumes of gas, to the Atlanta Gas Light Company (Atlanta). Southern claims that it has an executed service agreement with Atlanta whereby Southern is to supply Atlanta with its natural gas requirements for the City of Atlanta except for 20,000 Mcf per day which Atlanta may purchase from Transco under Transco's CD–1 Rate Schedule and that the Southern-Atlanta agreement contemplates that Southern and Atlanta will negotiate in good faith for the sale and purchase of additional quantities of gas needed to meet any increase in Atlanta's natural gas requirements for areas now supplied with gas purchased from Southern (Item K by reference). In essence, Southern intervened only to determine whether the Transco-Atlanta proposal is in conflict or inconsistent with the alleged pre-existing and presently effective agreement between Southern and Atlanta. Southern presented no witness but did participate in cross examination and presumably obtained, as a result thereof, whatever information it needed in this respect to the extent that the same was available from the witnesses presented. The evidence does not show the Transco-Atlanta proposal to be inconsistent or in conflict with the Southern Atlanta agreement. Accordingly, Southern's participation as an intervener should have no effect on the merits of Transco's proposal to render service to Atlanta.

Seaboard is an existing customer of Transco but, as noted above, does not seek any additional service from Transco in these proceedings. Seaboard was permitted to intervene, as indicated above, in Transco's present rate proceeding in Docket No. RP61–13. In its petition to intervene in the present proceedings, Seaboard states that its intervention in Docket No. RP61–13 was "with respect to matters that may be affected by the outcome of this proceeding" and that "the arrangements proposed may affect Transco's cost of service and rates under which service is rendered to" Seaboard. The present proceedings, viz, CP61–194, *et al.*, involve *inter alia*, Transco's proposed General Storage Service (GSS) Rate Schedule and New York Natural's proposed General Storage Service (GSS–1) Rate Schedule. With respect to these two rate schedules, the Commission issued an order in Docket Nos. RP61–13 and G–19087 on July 31, 1961, wherein it stated *inter alia*, that "* * * it is appropriate that the Commission consider the justness and reasonableness of the changes set

forth in said filings and that such changes be incorporated for purposes of hearing with the respective proceedings in Docket Nos. G–19087 and RP61–13." Seaboard presented no witness but did participate in cross examination of certain witnesses. Seaboard did not voice any opposition to the grant of the application and, in essence, intervened only to protect its interest and participation in the RP61–13 rate proceedings. Seaboard stated that its participation in the present proceedings was and would be very limited because of the issuance of the aforesaid order on July 31, 1961. Accordingly, Seaboard's participation as an intervener does not raise any additional questions or problems with respect to the disposition of the applications on their merits.

Tennessee is the only intervener in opposition to the grant of any of the applications. It intervened in Docket Nos. CP61–194, 198, 237, and 238. In its petition to intervene, Tennessee claims an interest based on competition and further states that the storage proposals here involved are but another step towards ultimately excluding Tennessee from participation in the growth of the Philadelphia, New Jersey, and New York City market areas which are presently served by both Tennessee and the joint applicants. Tennessee also states that "Consolidated," the parent company of New York Natural, "has more than ample storage capacity to satisfy its storage needs for the present and indefinite furture"; that "New York Natural has excess storage capacity in its presently developed storage pools which is more than ample to cover the proposed service"; and that "it appears that Consolidated and New York Natural have agreed * * * to purchase * * * ACQ gas from Texas Eastern and Transco, with provisions to buy * * * more, while at the same time cutting back on lower priced gas from Tennessee" to the "financial injury" of Tennessee. Tennessee presented no witnesses but did participate extensively in cross examination.

In Docket No. CP61–194, Transco has applied to render the proposed 99,290 Mcf per day additional volumes of gas to 26 of its contract demand and general service customers, and also to increase long-term storage service to 11 of its existing customers. Transco proposes to construct and operate about 186.67 miles of 36-inch transmission pipeline loops, 23,400 horespower of compression, in existing and new compressor stations and 36.97 miles of 8, 6, 4 and 3-inch gas purchase laterals.

Transco was authorized, under temporary certificates, to construct all of the proposed pipeline loops and one new 4,000 horsepower compressor station on its gathering system in Louisiana. Construction of these facilities commenced soon after the granting of the temporary authorization. On September 21, 1961, the Commission declined to grant Transco temporary certificate to construct the remaining compressor facilities because of Tennessee's opposition. Transco contends that the additional compressor facilities are needed to provide the proposed additional storage service on a long-term basis and also to enable it to take the "valley" gas from south of the Potomac River in summer to customers north of the river to meet their full allocations. Transco further contends that the elimination of this summer bottleneck south of the Potomac has permitted it to operate at over 98 percent load factor in the past several years.

The tabulation below shows, in summary, the facilities for which Transco is seeking authorization herein and the costs of such facilities.

	Estimated cost
Part I—Main Line Facilities	
A—186.67 miles of 36-inch main line loops in the states of Louisiana, Mississippi, Alabama, Georgia, South Carolina, North Carolina, Virginia, and Maryland	$25, 936, 581
B—13,400 additional compressor horsepower and other related additional facilities at six existing main line compressor stations	3, 675, 730
Part II—Gathering Facilities	
C—New Intermediate Station No. 63 in southeast Louisiana with 4,000 compressor horsepower and the related piping and dwellings	1, 570, 000
D—36.97 miles of 8-, 6-, 4-, and 3-inch gas purchase laterals and six gathering meter and regulator stations offshore southeast Louisiana	1, 959, 006
Part III—Leidy Line	
E—New Intermediate Station No. 505 with 6,000 compressor horsepower and the related dwellings	2, 700, 400
Part IV—Sales Facilities	
F—Two meter and regulator stations one for Public Service and one for Atlanta Gas Light	63, 700
Total direct cost	35, 905, 417
Franchise, Consents, General Overheads, Interest during construction and Contingencies	4, 478, 583
Total estimated costs	40, 384, 000

The proposed facilities will increase Transco's sales capacity by approximately 107,893 Mcf per day, which would enable Transco to render the proposed additional contract demand and general services (total 99,290 Mcf per day at 14.73 psia), and have 8,603 Mcf per day of unallocated capacity available anywhere on the system. Transco's total peak day capacity is outlined in the following table:

	Mcf per day at 14.7 psia
Contract Demand and General Service:	
1—Firm allocations all previous dockets	1, 377, 521
2—Proposed pipeline allocations	99, 290
3—Unallocated firm pipeline capacity	8, 603
Subtotal	1, 485, 414
Storage and Transportation:	
4—Oakford storage allocations	136, 452
5—Leidy storage allocations	204, 000
6—Docket CP61-194 proposed storage allocations	150, 000
7—Transportation for Tennessee	56, 216
Total peak day capacity	2, 032, 082

Transco proposes to use the proposed facilities for the purpose of rendering long-term firm services to its existing customers as tabulated below:

Proposed additional pipeline service to existing customers

	Rate schedule	Mcf per day at 14.7 psia
Consolidated Edison Company of New York, Inc.	CD-3	38,000
Delaware Power & Light Company	CD-3	4,000
Elizabethtown Consolidated Gas Company	CD-3	1,000
Philadelphia Electric Company	CD-3	5,000
Public Service Electric & Gas Company	CD-3	15,000
South Jersey Gas Company	CD-3	7,000
United Gas Improvement Company, The	CD-3	5,000
Carolina Natural Gas Corporation	CD-2	700
Danville, Virginia, City of	CD-2	1,000
Fort Hill Natural Gas Authority	CD-2	2,610
Public Service Company of North Carolina, Inc.	CD-2	7,000
Atlanta Gas Light Company	CD-1	6,000
City Gas Company of New Jersey	G-3	680
Frederick Gas Company, Inc.	G-3	450
Manufacturers Light and Heat Company	G-3	310
Blacksburg, South Carolina, City of	G-2	50
Clinton, South Carolina, City of	G-2	1,710
Lexington, North Carolina, City of	G-2	800
Newberry, South Carolina, City of	G-2	900
South Carolina Gas Company, Division of United Cities Gas Company	G-2	200
Buford, Georgia, City of	G-1	330
Covington, Georgia, City of	G-1	400
Georgia Gas Company, Division of United Cities Gas Company	G-1	500
Lawrenceville, Georgia, City of	G-1	250
Maplesville, Alabama, City of	G-1	100
Monroe, Georgia, City of	G-1	300
Total		99,290

Proposed storage service

	Rate schedule	Mcf per day at 14.7 psia
Atlanta Gas Light Company	GSS	31,000
Brooklyn Union Gas Company	GSS	25,000
Consolidated Edison Company of New York, Inc.	GSS	15,000
City of Danville, Virginia	GSS	2,000
Delaware Power and Light Company	GSS	2,000
Elizabethtown Consolidated Gas Company	GSS	4,000
Long Island Lighting Company	GSS	10,000
Piedmont Natural Gas Company	GSS	15,000
Public Service Electric and Gas Company	GSS	31,500
South Jersey Gas Company	GSS	4,500
United Gas Improvement Company	GSS	10,000
Total		150,000

These additional volumes are required by these existing customers of Transco for normal growth in their present operations and are justified by the record, including the evidence of the market company witnesses, and the exhibits presented.

For the storage service, Transco is seeking to obtain from New York Natural 150,000 Mcf per day of storage service annually for 50 days during the winter season in order to render a like service to its customers. This volume indicates a need for top storage capacity of 7,500,000 Mcf.

The volumes of gas Transco's customers nominate for injection into storage, Transco delivers to New York Natural in western Pennsylvania at the Leidy storage pool where their two systems interconnect, and New York Natural will store the gas anywhere on its general system storage facilities. In winter when Transco's customers demand this storage gas, Transco notifies New York Natural, which will return the stored gas.

Transco is not proposing in this proceeding to develop any storage pool of its own. The storage service proposed by Transco will be rendered under a rate schedule called GSS which is before the Commission in Docket No. RP61–13.

The additional markets involved in Docket No. CP61–194 are as follows:

(1) Docket No. CP61–208—Town of Liberty, Mississippi—The town of Liberty and environs, including the community of Gillsburg, Mississippi, a municipality, filed a 7(a) application in Docket No. CP61–208 on February 8, 1961, as amended March 10 and July 12, 1961, for an order requiring Transco to supply it with the following volumes of gas at 14.73 psia under Transco's Rate Schedule G–1.

	1st year	2d year	3d year
Peak day	458	499	531
Annual	37,506	40,770	43,235

The facilities proposed by the town of Liberty, which include 15.5 miles of 3-inch lateral line and a distribution system, including regulator and metering appurtenances, are estimated to cost $275,000. This cost will be financed through the issuance of 30-year revenue bonds at 3⅜ percent interest. The debt coverage ratio, assuming gas purchases level off at the end of the 3rd year, would be 1.88, while the overall ratio of the 30-year bond issue would be 2.18. A letter of commitment by Allen & Co., Hazelhurst, Mississippi, confirms the financing program.

The area is mainly agricultural and the estimated number of customers is based on an actual house to house survey. The estimated cost of the construction is based on the lowest bid. The annual system expenses are based on experience in several of the neighboring towns and communities.

The Public Service Commission of the State of Mississippi has granted the town of Liberty a certificate authorizing the instant project. No question appears to be raised concerning the economic and financial feasibility of Liberty's project in view of the receipt of the certificate from the State.

(2) Docket No. CP61–222—The Wind Gap Division of Bangor Gas Company, a subsidiary of Penn Fuel Gas, Inc., filed a 7(a) application in Docket No. CP61–222 on February 28, 1961, as amended June 27, July 20, and October 23, 1961, for an order directing Transco to establish physical connection with the contemplated facilities of Wind Gap and to supply it with the following volume of gas at 14.73 psia under Transco's Rate Schedule G–3.

	1st year	2d year	3d year
Peak day	223	259	297
Annual	47,240	51,460	56,100

Of these volumes, about 50 percent is proposed to be sold to one industrial consumer, namely, Supradur Manufacturing Co. The President of Wind Gap testified as follows:

> Wind Gap Gas Company possesses all requisite state authorization, and by that I mean appropriate corporate authority and franchise authority conferred by the Pennsylvania Public Utility Commission, to serve in the Borough of Wind Gap and the Township of Washington and Plainfield, Northamton County, Pennsylvania.

On March 7, 1960, the Borough of Wind Gap enacted Ordinance No. 193 which conferred upon Penn Fuel Gas, Inc., the authority to enter upon the streets of the Borough. On March 1, 1961, Penn Fuel assigned all its rights under that ordinance to Bangor Gas Company.

The Wind Gap facilities, which include 4,200 feet of 4-inch lateral line from a tap on Transco's Leidy line in Northampton County to the Borough of Wind Gap and the contemplated distribution system, are estimated to cost $80,000. This is to be financed by advances from the parent company, Penn Fuel Gas, Inc. The rate of return is estimated at 11.9 percent.

The estimated number of customers is based on an actual house to house survey. Wind Gap's witness claims that the largest prospective industrial customer, the Supradur Manufacturing Company, has committed itself to buy from Wind Gap 145 Mcf per day of natural gas.

This "commitment" was based on a letter[9] (Item G by reference) which indicates that Supradur would be interested in buying gas if the price were competitive with other fuels. Accordingly, the authorization provided herein for the service in Wind Gap is conditioned on its showing within six months, that Supradur has firmly committed itself to buy the volumes estimated.

(3) Docket No. CP61-223—The Hughesville Division of Jersey Shore Gas & Heating Company, a subsidiary of Penn Fuel Gas, Inc., filed a 7(a) application in Docket No. CP61-223 on February 28, 1961, as amended on May 31 and October 23, 1961, for an order requiring Transco to establish physical connection with the contemplated facilities of Hughesville and to supply it with following volumes of gas in Mcf at 14.73 psia under Transco's Rate Schedule G-3.

	1st year	2d year	3d year
Peak day	97	128	181
Annual	24,570	32,760	46,360

Authorization by the Pennsylvania Public Utility Commission is pending. Authorizations by the Boroughs of Picture Rocks and Hughesville have been granted.

The Hughesville facilities which include 16,000 feet of 4-inch pipeline extending from a tap on Transco's Leidy line in Lycoming County to the Boroughs of Picture Rocks and Hughesville and the contemplated distribution system are estimated to cost $144,960. This is to be financed by advances from the parent company, Penn Fuel Gas, Inc. The rate of return is estimated at 6.7 percent.

The estimated number of customers is based on an actual house to house survey. Hughesville's application as supplemented, indicates that 65 percent of its estimated requirements is for industrial customers; but that only four industrial customers have committed themselves to buy from Hughesville 3,320 Mcf annually, if natural gas becomes available at Hughesville. This constitutes about one-tenth of that part of the annual requirement, which is earmarked for industrial customers. Accordingly, the authorization provided herein for service in Hughesville is conditioned on its showing, within six months, that the industrial sales are firmly committed as estimated.

(4) Pittston Gas Company, a subsidiary of Penn Fuel Gas, Inc., and an existing customer of Transco, petitioned to intervene in order to secure an additional

[9] This is the letter which is dated October 20, 1961, included in Wind Gap's Third Supplement to its application in Docket No. CP61-222. Wind Gap's reference in its brief to "an intent to purchase by Supradur" is a reference to this letter.

allocation of gas. The additional volume sought by Pittston to meet its increased requirements in its existing market area is 401 Mcf per day. Pittston's peak day gas requirement and supply in Mcf per day at 14.7 psia are as follows:

	1961–62	1962–63	1963–64
Requirement	1,142	1,386	1,623
Supply:			
Existing	741	741	741
Proposed	401	401	401
	1,142	1,142	1,142

(5) Pennsylvania Gas and Water Company, a customer of Transco, also intervened. It buys gas from Transco for an isolated small system near Dallas, Pennsylvania, which is not involved in these proceedings.

Pennsylvania Gas and Water's other natural gas operations are in two separate unconnected market areas, namely the western and the eastern market areas. For its western market area, which is not involved in these proceedings, Penn Gas gets its natural gas supply from The Manufacturers Light and Heat Company. Its intervention here concerns its eastern market area, which consists of Uniondale, Carbondale, Scranton, Nanticoke, Wilkes-Barre, numerous boroughs and townships in Lackawanna County, and in Luzerne County and also the Borough of Factoryville, Wyoming County. For this area it gets its gas supply from Tennessee. The annual peak day gas requirements of Penn Gas's Eastern System in Mcf at 14.73 psia, to which the instant request for additional supply from Transco refers, are as follows:

	1961	1962	1963
Annual	3,653,100	4,198,200	4,670,100
	1961–62	1962–63	1963–64
Peak day	15,733	18,231	20,553

Penn Gas has a long-term allotment of 13,200 Mcf per day from Tennessee for this area and a short-term or interim allocation of 2,533 Mcf per day (CP61–295, et al.) from Tennessee, or a total of 15,733 Mcf. The interim volume extends only until November 30, 1962. At that time, Penn Gas wants to start buying 2,533 Mcf per day from Transco, in lieu of Tennessee on a long-term basis. It desires this, along with two new connections with Transco's Leidy line in this area, to assure the area of service in case of an emergency break on its system. It states that this break could occur, cutting off all existing service, because the area is subject to subsidence due to anthracite coal mining. It already has had difficulties in this respect.

The service and connections with Transco plus the connection and existing long-term service from Tennessee would solve its problems. Neither Transco nor Tennessee opposes the proposal. In its amended application in CP60–94, Tennessee proposes to sell additional long-term gas to Penn Gas for the 1962–63 winter to meet the increasing needs of the area. This volume converts the 2,533

Mcf [10] of interim gas to long-term and adds 2,498 Mcf of additional long-term gas, or a total of 5,031 Mcf.

The cost of the proposed connections and facilities to Penn Gas is estimated as follows:

East side of Susquehanna River connection and measuring and pressure reduction station	$50,000
West side of Susquehanna River emergency connection involving 14,000 feet of 10-inch pipeline and skeletonized meter and pressure reduction station	150,000
Total	200,000

As it has been shown, Transco's system (including the proposed facilities) has the firm unallocated capacity of 8,603 Mcf per day at 14.7 psia. The five allocations requested above add up to 3,943 Mcf per day, and if Transco is ordered to supply this amount, then Transco's remaining firm unallocated capacity will be 4,660 Mcf per day.

The cost of Transco's entire project in its application in Docket No. CP61–194 is estimated to be $40,384,000 including $4,478,583 for overheads, interest during construction, contingencies, franchises and consents. The estimates appear to be in line with the 1960 average cost figures available to the staff. No changes in rates are proposed. The present rates have been in effect, subject to refund in Docket No. RP61–13, since April 17, 1961.

Transco estimates its system return for the first three years of the proposed service to be respectively 6.58 percent, 6.57 percent, and 6.63 percent based on rate schedules filed in Docket No. RP61–13. The incremental return attributable solely to the instant proposal is calculated to be approximately 11.39 percent for 1962, 12.1 percent for 1963 and 12.4 percent for 1964. This reflects an estimated system average cost of gas of 18.50 cents per Mcf in 1962, 18.7 cents per Mcf in 1963 and 18.7 cents per Mcf in 1964.

The financing of the proposed project and other facilities already authorized or still pending before the Commission is to be accomplished by the issuance of securities in the amount of $40,000,000 as set forth below in addition to $35,000,000 of five percent first mortgage pipeline bonds which were issued May 2, 1961, and which are due in 1981.

	Principal amount	Proposed date of issuance
Debentures: 5¾%, due 1982	$25,000,000	Feb. 1, 1962
Preferred stock: Cumulative 5¾%	15,000,000	Feb. 1, 1962
Total proposed securities	40,000,000	

No questions are raised concerning the financing of Transco's proposals.

For its proposed service, Transco relies on independent natural gas producers who have received temporary or permanent certificates. In its application in the subject Docket No. CP61–194, Transco proposes lateral facilities in the Ship Shoal South Pelto area to receive offshore gas from ODECO in the two

[10] The authority granted herein renders duplicative the application by Tennessee in Docket CP60–94 to serve the same volume of 2,533 Mcf to Penn Gas. It is understood that Tennessee recognizes that its application is unnecessary in view of Tennessee's withdrawal of opposition to the service by Transco.

applications described below. Transco asked for and was granted temporary authorization on May 8, 1961,[11] to construct and operate the related offshore facilities.

On April 10, 1961, Ocean Drilling & Exploration Company filed an application in Docket No. CI61–1469 on its own behalf and, as the operator, on behalf of Burmah Oil Western Company to sell natural gas to Transco from Block 113 unit, Ship Shoal area, offshore Louisiana in conformity with their sales contract of March 8, 1961, with Transco.

On May 29, 1961, ODECO also filed for authority in Docket No. CI61–1708 to sell gas to Transco from W/2 Block 19 and Block 20 units, South Pelto area, offshore Louisiana.

These sales are to be heard in the area proceedings, Docket No. AR61–2. Pending their final authorizing, ODECO on September 5, 1961, filed applications for temporary authorization with respect to these two sales. ODECO was granted temporary authorizations on October 17, 1961. The authorizations are subject to ODECO refunding to Transco any amounts collected, plus interest at 7 percent per annum, in excess of the rate determined to be required by the public convenience and necessity.

The adequacy of Transco's gas supply was demonstrated by substantial evidence of its sufficiency. No participant in the proceeding raised any question with respect to Transco's gas supply. Transco's estimates of reserves and deliverability are set forth in Exhibit 8. A summary of Staff's analysis is set forth below:

All Volumes @ MMcf @ 14.73 psia

(1) Total recoverable gas reserves available to Applicant by contracts as of 1–1–61:	
Flow tested	7,790,241
Tested with Formation Tester	130,530
Non-flow tested	536,329
Pipeline purchases	924,255
Total by contract	9,381,355
(2) Spot gas purchases estimated @ 5% of firm gas purchases for 21 years	460,893
(3) Total estimated gas available for 21 years	9,842,248
(4) Market requirements 21 years	11,193,907

	Flow tested only	Non-flow tested included
(5) System's reserve life index (years):		
Transco's method	16.1	17.2
Staff's method	15.6	16.6
(6) System's deliverability life as of 1–1–62 (years):		
Transco's method	12.91	13.97
Staff's method	12.00	13.00

As shown in the tabulation, 130,530 MMcf of the gas reserves have been shown by Transco as being flow tested, but not through tests in which gas was produced at the surface. The proof of the existence of gas in the formation was based on tests conducted with the Schlumberger Formation Tester. A witness employed by Schlumberger testified in the hearings as Transco's witness in regard to the Tool's principles, its method of operation, and compared the predictions provided by the tests, with actual later production data. The Staff is in agreement that the formation tester could be used to establish proof of gas in a formation in productive quantities, but it is also of the opinion that the tester has limi-

[11] On May 8, 1961, ODECO was granted conditional temporary authorization to sell gas to Transco from its Ship Shoal area Block 67, South Louisiana.

tations in its use. The 130,530 MMcf of gas, claimed by Transco as proven, are believed to be reasonable and within the limits of the dependability so established.

To meet the additional demands on its storage service (by Transco and other customers), New York Natural is seeking authorization in the following three applications.

New York Natural seeks a certificate in Docket No. CP61–198 authorizing it to render storage service to Transco in the 1961–62 season in the amount of 3,750,000 Mcf and to double that volume as of April 1, 1962 and thereafter.

New York Natural requested temporary authorization in order to commence gas injection during the injection season and prior to its withdrawal next winter. Temporary authorization to render storage service up to 75,000 Mcf per day for Transco only for the period ending May 1, 1962, was granted on June 26, 1961.

New York Natural's entire natural gas facilities are divided into two groups. One is designated the "OSS System," and the service rendered by this system is mainly to applicant's affiliates. It comprises Oakford and South Bend storage pools near Pittsburgh, Pennsylvania, and the pipeline facilities extending westerly from these pools to two of its affiliates, namely, the East Ohio Gas Company and the Peoples Natural Gas Company.

The other group of facilities is called the "General System," and the service rendered by this system is mainly (but not exclusively), to 16 non-affiliated companies in Pennsylvania and New York for resale. The proposed storage service to Transco is to be rendered from this system, particularly from its five existing storage pools, and such additional storage facilities which New York Natural may develop and activate in the future, including those proposed in its applications in Docket Nos. CP61–237 and 238 described later herein.

New York Natural's General System consists of its main pipeline system, which extends in a northeasterly direction, from the West Virginia-Pennsylvania border in Greene County, Pennsylvania, through the State of Pennsylvania into the State of New York to points near such cities as Buffalo, Rochester, Syracuse, Auburn, Utica, and Albany. The General System also includes five existing active underground storage pools with claimed existing top storage capacity of 111 billion cubic feet at 15.025 psia and several additional pools with a claimed ultimate capacity of 153 billion cubic feet at 15.025 psia, including storage development requested in these proceedings.

New York Natural and Transco have executed a precedent agreement, dated January 6, 1961, covering the proposed storage service. The agreement is for 20 years from April 1, 1961. According to this agreement, for the period ending March 31, 1962, New York Natural will receive and store, during the injection period of the year 1961 (April through October), for the account of Transco, the maximum volume of 3,750,000 Mcf and will withdraw, for the account of Transco, during the withdrawal period (November 1961 through March 1962), the maximum volume of 75,000 Mcf per day. The agreement further provides that for the period beginning April 1, 1962, and thereafter, New York Natural will receive and store, during the injection period of each year, for the account of Transco, the maximum volume of 7,500,000 Mcf and will withdraw, for the account of Transco, during the withdrawal period of each year, the maximum daily volume of 150,000 Mcf. New York Natural further agrees to increase its annual and daily storage commitments to Transco respectively to 10,000,000 and 200,000 Mcf as of April 1, 1963, 1964, or 1965 for the remaining term of the agreement, if Transco shall give 18 months prior notice. Only the proposed service of up to 150,000 Mcf per day is covered by the instant application in Docket No. CP61–198. Authorization for the service of up 200,000 Mcf per day will require a further application by New York Natural.

The instant application is for authorization to render the proposed storage service to Transco under New York Natural's proposed new Rate Schedule GSS–1. The point of delivery to Transco will be the existing interconnection of the pipeline system of New York Natural and Transco at the Leidy storage pool, Clinton County, Pennsylvania. However, New York Natural is not restricted to the use of Leidy to render the GSS–1 service. It proposes to use any or all of its available general system storage pools to render the proposed storage service to Transco.

New York Natural seeks a certificate in Docket No. CP61–237 authorizing it to develop and operate existing properties and facilities for underground storage of gas in an Oriskany sand, known as the Greenlick pool, which is located in northern Pennsylvania, near Leidy and which has a claimed ultimate capacity of 53 billion cubic feet, when developed to its initial rock pressure.

New York Natural states that the Greenlick field is a gas producing field at present, owned and operated by New York Natural. It claims that Greenlick field can easily be converted into a storage pool with the use of existing production and gathering facilities in the field. No additional facilities are proposed in this application.

New York Natural anticipates that when the authorization requested herein is granted, it will commence injection of gas into Greenlick. During the injection season it estimates that 5 billion cubic feet of natural gas can be injected into the pool with its existing facilities. It states that of the 5 billion cubic feet, two billion cubic feet will be cycled as top storage gas.

This development is indicated to be a continuation of New York Natural's policy to further develop its underground storage facilities for serving its existing customers and also to enable it to render the long-term storage service to Transco as proposed in its application in Docket No. CP61–198.

The company further states that with the development of Greenlick storage pool, it will be able, during off-peak periods, to inject "commodity—cost-gas," which it has contracted to purchase, but which cannot otherwise be utilized by the system. Such gas would be available in winter periods to replace higher cost gas.

It was indicated that the temporary authority requested in this docket will help New York Natural store gas available to it from its suppliers, in off-peak periods in 1961, for which it has no other use at that time and also help it render the proposed 75,000 Mcf per day of storage service to Transco.

New York Natural was granted temporary authorization on June 23, 1961, to develop and operate the Greenlick storage field for the proposed total storage capacity of 5 billion cubic feet. Gas injection into the pool started on June 28, 1961.

New York Natural, Texas Eastern Transmission Corporation, and Transco seek a certificate in Docket No. CP61–238 authorizing the construction and operation of certain facilities in order to further develop and activate additional underground storage capacity in the Leidy storage pool, pursuant to Amendment No. 4, dated February 28, 1961, to the Leidy-Tamarack [12] Transfer Storage and Agreement between the joint applicants. The portion to be developed is one-third of New York Natural's share of the Leidy storage capacity. Its share is one-half of the total Leidy capacity. Texas Eastern and Transco have already been authorized to develop their respective one-fourth shares. The top storage capacity of the Leidy pool is 54 million Mcf and the top storage capacity of the Tamarack pool is 6 million Mcf.

[12] Shortened herein to "Leidy."

The three joint applicants entered into amendatory agreements Nos. 1, 2, and 3, dated March 2, 1959, July 6, 1959, and April 14, 1960, respectively, which provide for the development of Transco's and Texas Eastern's shares of Leidy top storage capacity of 15,000,000 Mcf each.

Authorization for their respective development and activation was granted in Docket Nos. G–13793 and G–18961.

On February 28, 1961, the three joint applicants entered into the 4th amendatory agreement to further develop the Leidy Storage pool to provide 10,000,000 Mcf of New York Natural's 30,000,000 Mcf of top storage capacity, which would make a total of 40,000,000 Mcf of developed top storage capacity. The application in Docket No. CP61–238 is for authorization to install and operate the requisite facilities outlined below to attain the proposed additional development and activation of the Leidy storage pool. The 4th amendatory agreement further indicates that at the completion of the instant project, there will be a total of 41,000,000 Mcf of base storage gas in Leidy and it provides that Transco and Texas Eastern will each supply half of the base gas. Of this total volume, Transco and Texas Eastern have already supplied 30,400,000 Mcf of base storage gas. The remaining volume of 10,600,000 Mcf of base storage gas will have to be supplied by them in equal portions prior to the completion of the proposed program. As indicated earlier, it is believed Transco will have no difficulty in providing this quantity, nor should Texas Eastern, through the use of off-peak capacity.

The proposed facilities of New York Natural in Leidy and their estimated costs are as follows:

Two new wells to be drilled	$218,840
Pipelines and measuring equipment	159,460
Compressor station addition (4,000 horsepower)	2,484,000
Total proposed additional facilities	2,862,300

The estimated cost to date of the development of the Leidy pool is given to be $22,090,125. Together with the proposed facilities, the total cost will be $24,952,425 (not including base storage gas) and this will be shared by the joint applicants.

The Staff has submitted computations and an extensive analysis of New York Natural's gas supply and storage capacity and has concluded that the existing storage capacity plus the requested Greenlick storage pool will be adequate to render all of New York Natural's proposed service, without the activation of the Leidy pool. New York Natural has commented in its reply brief that both Tennessee and New York Natural are agreed at least on one factor in this consideration, that it is necessary to note the important distinction made by New York Natural in its gas supply and requirements, between the requirements of annual withdrawal of 55,805 MMcf and the peak day withdrawal of 981 MMcf, emphasizing that both such peaks cannot occur during the same withdrawal season. From this premise, New York Natural has contended that the Staff has made its computations on the basis that both such peaks could occur in the same withdrawal season, and that such is the error that is the basis of the equally erroneous conclusion respecting the lack of need of the Leidy field. The record confirms the New York Natural assertion that its computations and estimates of needs for gas withdrawal for these two peak periods, were based on the premise that both would and could not occur in the same withdrawal season. The record also supports the conclusion that there will exist the following general system annual and peak day storage capacity in New York Natural storage pools:

45,905 MMcf at 15.025 psia (46,824 at 14.73 psia) for annual capacity and 517 MMcf at 15,025 psia (527 at 14.73 psia). These computations compare with anticipated requirements for the 1963–64 requirements of 46,116 MMcf annually and 968 MMcf peak day on the 15.025 basis. The difference between available storage supply and requirements represents the need for which both the Greenlick and Leidy storage pools are required, and authorization for which is provided herein.

The rate aspect of the storage service proposed to be rendered by New York Natural to Transco was most strenuously contested by Tennessee, partly on the asserted ground that base storage costs were not adequately reflected in the rate proposed by New York Natural for this service, and also partly contested by the contention that the level of this rate represented a device undertaken by New York Natural to ultimately deprive Tennessee of the maximum sales of gas that Tennessee desires to sell New York Natural under an existing contract. Tennessee contends that if New York Natural would not reduce, or cut back, on its purchases of Tennessee gas, in the future years, that New York Natural gas supply costs would be less, and therefore it is in the public interest to require New York Natural to continue maximum purchases from Tennessee.[13] As to this latter contention, the reduction or cut back in gas purchases by New York Natural is presumably proposed in accordance with contract rights, which were a part of an unrelated proceeding before the Commission, when New York Natural presented this gas supply contract for consideration and approval. The exercise of rights by New York Natural in accordance with an Order of this Commission, approving the inclusion of the Tennessee contract as a part of gas supply is beyond the collateral attack on that order in this proceeding. If the exercise of those rights for a reduction in the amounts of gas purchased is not in the public interest, as Tennessee has indicated, then some other proceeding might or should be utilized, perhaps with Tennessee as an informant urging the Commission to act in its own capacity to inquire into these charges. This process may permit Tennessee to have the opportunity to develop all the facts it possesses, or, perhaps Tennessee, as a party, might seek to reopen the gas supply proceedings, of which its contract with the cut back provisions was a part, so that all aspects of this contract performance can be available for consideration by the Commission. The economic basis utilized for the justification of this Tennessee gas supply contract, in the initial and authorizing proceeding, which Tennessee contends will be cut back or reduced, cannot be reached in this consolidated [14] hearing.

The additional claim by Tennessee that adequate base storage costs, for the proposed service to Transco, are not adequately shown in the record, rests in part upon its assertion that the entire operations, with revenues and costs, of the Consolidated Natural Gas System, of which New York Natural is a part, must be presented. While it is true that New York Natural is operated as a part of the system, and that its gas supply is in a sense "pooled" according to over all system requirements, that is, the supply is dispatched from one part of the system to another, the evidence in this record is that such dispatching of gas is undertaken only when the sender has a surplus over requirements. The

[13] New York Natural denies this Tennessee contention and NYN asserts that Tennessee gas is the highest priced gas available on the entire Consolidated system. In addition, New York Natural asserted that if the Leidy field is activated, purchases of Tennessee gas will be larger than in previous periods. Neither of these assertions on gas costs is supported by the record.

[14] Likewise, the contention of a somewhat modified unfair competition, as asserted by Tennessee, if it rests on this same factual basis, which was not otherwise supported in this record, may also be a part of another proceeding.

rate aspect contested by Tennessee seeks to inject matters beyond the scope of a review of rate justification necessary in a certificate proceeding, as to which the consideration of adequacy and reasonableness of a proposed rate is less extensive than in a formal rate case. Sufficient for this proceeding is the necessity of the finding that the proposed service is feasible upon the basis of the proposed rate. In this respect, both the evidence by New York Natural, including Exhibit 54, and by Tennessee, including its Exhibit 60, amply support the finding, here made, that upon the costs and revenues reflected by the evidence in this record, and the gas supply available and deliveries required, the rate proposed by New York Natural will render the proposed gas storage service for Transco feasible and reasonably compensatory, to provide adequate basis that in this certificate proceeding the proposed rate is reasonable and therefore is accepted.

Remaining contentions by Tennessee respecting New York Natural operations, are largely concerned with the mode of operation of the New York Natural system, and related operations of the Consolidated Natural Gas System, particularly the storage pools, and also the assignment of gas supply, in some instances, to purchasers affiliated with New York Natural in the Consolidated system. Bearing in mind that Tennessee did not support its intervention by any direct evidence from witnesses, its contentions largely rest upon computations of costs and quantities of gas supply that do not appear fully in conformity with all of the evidence from which its computations were derived. It may be that if Tennessee's position had been set forth by direct evidence from witnesses, its contentions would be more firmly established, and would have permitted cross examination by those opposing, who must now rely upon answering argument based on different premises, for, as Tennessee concedes, in effect, in its brief,[15] it is difficult to know the New York Natural costs, or to ascertain the facts which would definitely establish Tennessee's position. On the basis of this record, the remaining contentions of Tennessee respecting New York Natural and its applications, as well as Tennessee's proposed findings and conclusions submitted in conformity with it contentions, are rejected for lack of adequate proof to support the positions asserted. The serious character of the allegations made by Tennessee in its petition to intervene respecting unfair competition, monopoly of gas supply in the New York City market,[16] and lack of public

[15] Tennessee states in its brief:

"In view of the fact that no evidence whatsoever has been adduced with respect to the Consolidated Natural System, of which New York Natural is an integral part, and notwithstanding the attempts by Tennessee to obtain such information, it is impossible to determine the relative costs to New York Natural of gas purchases from various suppliers."

This lack of knowledge and absence of factual presentation does not aid an affirmative showing needed for Tennessee's position.

[16] In its brief, Tennessee concludes, without positive assertion, by stating:

"The cutting of prices by two natural gas companies in order to obtain a competitive advantage to the detriment and damage of another pipeline company serving the same customers, may well be a violation of stringent Federal law which condemns such unfair practice."

These are serious charges to be made within the gas industry, and Tennessee did not specify the particular Federal law alleged to be infringed.

The absence of a direct presentation by Tennessee indicates either that Tennessee preferred not to provide a complete support for these alleged trade practices, or, preferred to rely upon the hope that its attorney could discover enough weaknesses in the case presented by the adversaries to support the affirmative charges that Tennessee authorized to be made.

Implicit with every order by the Commission granting intervention is the obligation to make a direct presentation of evidence to support the petition, especially if objections are asserted to the allegations thereof, unless the person, in whose proceeding the intervention was granted, accords recognition or stipulates to the interest asserted.

interest in a proposed reduction, or cut back, in purchases by New York Natural of Tennessee gas have not been established by sufficient and substantial evidence. Tennessee's position was developed principally by cross examination, only, of the several witnesses presented by the applicants in this proceeding. This conclusion is not in any sense a dismissal of such charges, if a basis exists for consideration thereof; but on this record, there is insufficient foundation for Tennessee's assertions of an affirmative case, based upon its cross examination, and the computations and arguments made, therefrom.

Tennessee has also attacked Transco's rates for the storage service, by utilizing computations and references to Transco's evidence in a then pending rate case showing a loss for storage service, for Tennessee's contention that the Transco rate is too low. While Transco did not concede that its rate case claims were somewhat exaggerated, the evidence that Transco presented in this case, with the costs shown at $2,198,582, reflected by the expected payment to New York Natural for the service, and anticipated revenues of $4,222,166 from the storage customers provides a substantial credit to be applied to over all pipeline system costs incurred for the gas procurement and its transportation. Equally important is the indication by the Commission that a determination would be made in the pending Transco rate case [17] of the reasonable storage rate for the service here involved.

In any event, this record contains adequate and substantial evidence sufficient to accept, in this certificate proceeding, the level of the rate reflected in Transco's proposal. Tennessee raised the question concerning a winter peaking service, alleged to be offered by Transco as a part of the storage service. This aspect of the service was not developed on the record; the terms of the tariff indicate that the service is optional. This phase of the tariff may warrant precise inquiry if and when service is rendered according to options asserted for the service.

The Natural Gas Act requires the finding in the positive that the rates are shown to be reasonable, and Transco has presented the same general support for the storage and alleged peaking service rate, heretofore identified, for the complete feasibility showing. This over all presentation supports the rates proposed in the storage tariff as reasonable and compensatory to render the service economically feasible; that is, in a consideration of all of the evidence there is substantial basis to permit the finding that sufficient revenues are expected from the proposed rate to pay the reasonably supported costs of the service. As Tennessee concedes,[18] a certificate proceeding is not the occasion to determine if the rate is just and reasonable, but whether the service will be rendered with rates to make the project feasible. On this basis, the Transco rate fulfills the test. Tennessee contends, as to the winter peaking service; "* * * these rates could just as well have been pulled out of the air." As indicated herein,

[17] With an existing rate case actually in progress at the time of this hearing, it is somewhat illogical to undertake a duplicate rate analysis in this proceeding, especially if we are to avoid the complaint of "Due Processitis" set forth by Davis (Aug. 1961 Am. B. Jour.). That author, however, in undertaking to espouse a popular theme, failed to observe, or recognize, the force of a statute compelling the identified agency to convene the hearings, in accordance with the Administrative Procedure Act, the compliance with which the author apparently objected.

[18] Tennessee states in its brief:

"We wish to emphasize that we do not contend that the justness and reasonableness of any rate or rates must be established in a certificate proceeding under Section 7 of the Natural Gas Act. What we do say * * * is that Transco (having stipulated a loss on storage service for test year in its rate case) * * * cannot avoid a clear showing that the rendition of the total service it proposes under that rate is economically feasible." [Summary in the parentheses added.]

It is concluded that this test of economic feasibility has been fulfilled in these proceedings.

another proceeding and another inquiry, if any, should proceed without prejudice from the determination here made in this regard.

The Staff questioned the necessity of Transco's proposed Compressor Station 505, which would be constructed on Transco's Leidy line extending from a point near Princeton, New Jersey to western Pennsylvania. The Staff position was that if Leidy pool were not to be authorized, Compressor Station 505 would not be necessary. Transco answers by stating that the record evidence shows this Station 505 is needed for general service requirements whatever be the determination respecting Leidy. The Staff did not question Transco's market evidence as presented by Transco customer companies. Such evidence establishes a need for the gas storage service, some of which will be rendered from the Greenlick field, which the Staff recommended for authorization. The need for Station 505 is the more so required with the authorization of Leidy, not only to move the volumes of gas, but to achieve the pressures needed.

Tennessee's position did not refer specifically to Station 505, but Tennessee did urge in its brief that Transco is overbuilding its pipeline system, not to serve needs of existing customers, but because Tennessee alleges that Transco will later seek authority from the Commission to render a new service, which might be authorized solely because no new facilities are needed. Tennessee continues in its brief: "There is no way to tell what further extra-capacity is being built into Transco's facilities under the guise of 'firm requirements' * * *." This lack of evidence does not establish an overbuilding, and consequently Tennessee's contention in this regard is rejected.

In regard to matters of gas supply, markets and proposed financing, none of which was the basis of cross examination, Transco represents that based upon estimated total system requirements for twenty years of 10,712,351 MMcf at 14.73 psia (including the additional sales proposed herein), Transco's total system gas reserves as of January 1, 1962, of 9,197,221 MMcf have a life index of 17.2 years. The deliverability life of Transco's dedicated gas reserves is estimated to be 13.97 years from January 1, 1962. Transco contends that if no credit whatsoever were given to Transco's dedicated proven gas reserves which were not flow tested, Transco would have a life index of 16.1 years from January 1, 1962, and deliverability life of 12.91 years from January 1, 1962. Transco has adequate gas reserves and deliverability to support both its presently authorized service and the additional service of existing customers herein proposed.

These facilities proposed by Transco to render the service sought to be authorized are adequate for the acquisition of gas supplies and the rendition of additional service proposed by Transco in Docket No. CP61–194. Without these facilities, Transco contends that it could not adequately provide its presently authorized firm service and the additional firm pipeline and storage service proposed in Docket No. CP61–194.

Upon completion of the proposed facilities, Transco will have an allocable system capacity of 1,485,414 Mcf, excluding storage service, and 1,975,866 Mcf, including storage. After the additional firm service proposed in this proceeding has commenced and the proposed facilities have been installed, Transco will have on its system 8,603 Mcf per day of capacity which will be available on a year-round basis to meet additional requirements for firm pipeline service.

The costs of the proposed facilities have been based on past experience in constructing similar facilities and upon current price quotations. The estimated costs are concluded to be reasonable and adequate.

During the years 1963, 1964, and 1965, the first three full calendar years following installation of the facilities proposed herein, and commencement of all the proposed firm pipeline and storage service for which authorization is herein

sought, Transco estimates that it will earn sufficient revenues from presently authorized service together with the service proposed herein, at presently effective rates,[19] to produce an estimated system utility rate of return of 6.57%, and 6.63%, and 6.63%, respectively. These data were prepared by Transco on the basis of the Leidy development authorized by the Commission in Docket Nos. G–13793 and G–18961, and as proposed in these proceedings in the joint application in Docket No. CP61–238. When considered on the basis of the Leidy development authorized by the Commission in Docket Nos. G–13793 and G–18961, the estimated system utility rate of return for the years 1963, 1964 and 1965 is 6.55%, 6.62%, and 6.61%, respectively. A comparison of these results shows the effect on Transco of the joint application in Docket No. CP61–238.

Transco asserts that the estimated system utility rate of return, under either set of facts, would be lower in each year but for the expansion program for which authorization is herein sought. Revenues from the proposed service exceed the estimated cost of service on the proposed facilities (including a 6½% rate of return) in each of the three years by at least $3,000,000.

In making these computations, revenues were calculated on the basis of estimated system sales and transportation deliveries to present customers, including those presently certified and those for which authorization is herein sought. The cost of gas was obtained by applying the contract price to the volumes to be purchased from each field, which volumes are based on projected withdrawals of the volumes required for the period indicated. Operating and maintenance expenses are based upon Transco's actual experience adjusted for known and experienced changes, including expenses applicable to the facilities proposed herein. Depreciation was computed in accordance with the Company's present policy.

On May 2, 1961, Transco sold $35,000,000 of first mortgage pipeline bonds, which funds are presently available to the Company for the purpose of completing its current construction program. In addition, Transco anticipates that it will sell approximately $40,000,000 of additional debentures and preferred stock in connection with the proposed construction program. This financing is designed to cover the cost of certain facilities heretofore authorized by the Commission in other dockets, certain facilities involving minor applications not yet granted, miscellaneous plant additions and the facilities for which authorization is sought in Docket No. CP61–194.

Upon completion of the proposed financing, Transco will have the following capital structure:

		Percent
Long-term debt	$394,306,000	64.2
Preferred stock	92,575,000	15.1
Common equity	127,127,482	20.7
Total	$614,008,482	100.0

The evidence in this record demonstrates the need by Transco's existing customers of the proposed additional firm pipeline service of 99,290 Mcf per day, and the proposed additional storage service of 150,000 Mcf per day. All of

[19] Transco's presently effective rates for the sale of gas for resale and transportation are the rates collected subject to refund at Docket No. RP61–13. The revenues applicable to the proposed additional storage service have been computed by applying the rates set forth in Rate Schedule GSS set out in Exhibit 14 in evidence, which rates are identical to those found in Transco's currently effective Rate Schedule LS.

this service will be provided to existing customers. Transco does not propose to serve any new area in this proceeding.

Southern Natural intervened and its participation has developed the request that a condition be attached to any certificate issued herein, so that gas deliveries by Transco to Atlanta Gas Light Company, from the authority issued in this proceeding, be prohibited from entry to or use in the Atlanta area. Southern contends that it has an all-requirements supply contract to furnish all the gas Atlanta Gas Light Company needs for the Atlanta area. Southern concedes that Transco is already supplying some gas for the Atlanta area. The circumstances by which this Transco service was provided were not detailed for this record. Southern apparently contends, nevertheless, that it has a rigid all-requirements supply obligation; whether it has heretofore been found that Southern cannot fulfill that obligation is not discernible on this record. In its brief, however, Southern states that Transco can deliver the gas for the Atlanta area, when Southern has limited Atlanta to its contract demand. This contention appears as an antithesis to delivering the full gas requirements. More importantly here, however, is that Atlanta Gas Light Company has asserted that all of the gas sought in these consolidated proceedings is for the Athens and Franklin areas. No evidence suggests anything to the contrary. It is here found that it is reasonable to rely upon these representations of Atlanta Gas Light Company. Southern injected a reference to another, but unconsolidated Transco proceeding where different issues might arise. Whatever those issues may be, and what is the force left to Southern's exclusive obligation to supply gas for all the requirements in the Atlanta area can better be determined in another proceeding.[20] On this record, it is unreasonable to impose the condition urged by Southern and its request therefor is denied.

In addition to the foregoing findings and conclusions which accept, modify and reject, as herein shown, the proposed findings and conclusions, submitted by the participants in this proceeding, specifically, it is determined that Tennessee's proposed findings and conclusions numbers 1, 2, 3, 7 (as to the first sentence only), 9 (as to the first sentence thereof), are accepted and numbers 4, 5, 6, 7 (as to the second sentence only), 8, 9 (as to the second sentence only), 10, 11, 12, 13, 14, 15, and 16, are rejected, as well as are rejected Tennessee's unnumbered conclusions. Staff proposed findings and conclusions which are described as recommendations numbers 1, 2, 3, 4, 5, 6, and 8 are accepted, and numbers 7 and 9 are rejected.

By way of summary, and supplementary to the foregoing findings and conclusions, also based upon a consideration of the entire record in this consolidated proceeding, the evidence adduced and the briefs filed, are the following findings and conclusions:

1. Transcontinental Gas Pipe Line Corporation (Transco), a Delaware corporation with its principal place of business at Houston, Texas, is engaged in the transportation and sale of natural gas in interstate commerce and hence is a natural gas company within the meaning of the National Gas Act, as heretofore found by the Commission in its Order of April 28, 1950 (Docket No. G–1277–9 FPC 32).

[20] It would be interesting to consider the development by Southern of its contention that it is in the public interest, apparently, for one pipeline to assert a prohibition under an alleged all-requirements obligation supply contract, in order to exclude another supplier, which could supplement a gas supply to a total amount which Southern cannot fully deliver. Southern would thus seek to assert a right to exclude another pipeline supplier, based upon Southern's obligation to supply gas rather than upon its performance; Southern must contend that it has a right to demand compliance by Atlanta, even though Southern is in default.

2. New York State Natural Gas Corporation (New York Natural), a New York corporation, having its principal place of business at Pittsburgh, Pennsylvania, is engaged in the transportation and sale of natural gas in interstate commerce and hence is a natural gas company within the meaning of the Natural Gas Act, as heretofore found by the Commission in its Order of October 27, 1942 (Docket No. G–312–3 FPC 844).

3. New York Natural is an integral part of the Consolidated Natural Gas System (Consolidated Natural) which System is composed of New York State Natural Gas Corporation, The East Ohio Gas Company (East Ohio), The Hope Natural Gas Company (Hope), Lake Shore Pipeline Company (Lake Shore), The Peoples Natural Gas Company (Peoples), and The River Gas Company (River).

4. Texas Eastern Transmission Corporation (Texas Eastern), a Delaware corporation, having its principal place of business in Shreveport, Louisiana, is engaged in the transportation and sale of natural gas in interstate commerce, and is a natural gas company within the meaning of the Natural Gas Act, as heretofore found by the Commission in its Order of October 10, 1947 (Docket No. G–880–6 FPC 148).

5. The facilities proposed to be constructed and operated under the authority sought in these consolidated proceedings would be used for the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission and the construction and operation of these facilities and sale of natural gas from these facilities, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

6. Transco, New York Natural, and Texas Eastern are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission, issued thereunder.

7. The construction and operation of the facilities described in the applications and amendments thereto, filed by Transco, New York Natural, and Texas Eastern and the sales of natural gas from these facilities in interstate commerce, subject to the jurisdiction of the Commission, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter provided.

8. The sale by Transco of additional amounts of natural gas as requested by Pittston Gas Company in interstate commerce, subject to the jurisdiction of the Commission, is required by the public convenience and necessity and a certificate therefor should be issued as hereinafter provided.

9. The sale by Transco of the amounts of natural gas, sought by Pennsylvania Gas and Water Company in these proceedings, and the construction and operation of the facilities needed for said sale of natural gas in interstate commerce subject to the jurisdiction of the Commission, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter provided.

10. The construction and operation of the facilities described in the Section 7(a) application and amendments thereto, of the Town of Liberty, Mississippi, in Docket No. CP61–208 and the sale of natural gas by Transco to the said town, as well as facilities needed to render such sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter provided.

11. The construction and operation of the facilities described in the Section 7(a) application and amendments thereto, of The Wind Gap Division of Bangor

Gas Company in Docket No. CP61–222, and the sale of natural gas by Transco to said company, as well as the facilities needed to render such sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, are required by the public convenience and necessity subject to the condition that said company demonstrate to the satisfaction of the Commission, within six months from the date of issuance of the Commission's order granting the instant application, that the Supradur Manufacturing Corporation has firmly committed itself to buy the estimated volumes of gas indicated in this proceeding and a certificate therefor should be issued as hereinafter provided.

12. The construction and operation of the facilities described in the application, and amendments thereto, of The Hughesville Division of Jersey Shore Gas & Heating Company in Docket No. CP61–223 and the sales of natural gas by Transco to said company, as well as the facilities needed to render such sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, are required by the public convenience and necessity, subject to the condition that said company demonstrate to the satisfaction of the Commission, within six months from the date of issuance of the Commission's order granting the instant application, that the industrial customers have firmly committed themselves to buy the estimated volumes of gas indicated in this proceeding, and a certificate therefor, subject to this condition, should be issued as hereinafter provided.

13. The development and operation of the designated Greenlick gas field as a natural gas storage pool, as described in the application, and amendments thereto, by New York Natural in Docket No. CP61–237 as integral parts of natural gas facilities used for sales of natural gas in interstate commerce, subject to the jurisdiction of the Commission, are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter provided.

14. The construction and operation of the facilities described in the joint application and amendments thereto of New York Natural, Texas Eastern, and Transco in Docket No. CP61–238 respecting and related to the designated Leidy gas storage pool for use in connection with transportation, storage and sale of natural gas in interstate commerce subject to the jurisdiction of the Commission, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter provided.

15. The construction and operation of the facilities described in application of New York Natural in Docket No. CP61–198 and the sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter provided.

16. Public convenience and necessity require that the general terms and conditions set forth in paragraphs (a), (b), (c), and (e) of Section 157.20 of the Commission's Regulations, under the Natural Gas Act (18 CFR 157.20) should attach to the certificates hereinafter issued to the companies and to the town designated in the foregoing findings and to the exercise of the rights granted thereunder, and that the time within which the facilities authorized by this order shall be constructed and in actual operation should be fixed at one year from the date on which this Order shall become effective.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal, or review by the Commission on its own motion, as provided in its Rules of Practice, that:

(A) Certificates of Public Convenience and Necessity are hereby issued, subject to all pertinent provisions of the Natural Gas Act, and the Commission's Regulations thereunder, including to the extent applicable paragraphs (a), (b), (c), and (e) of Section 157.20 of such Regulations, to the companies and to the town designated in the foregoing findings, authorizing the construction and operation of facilities and the sale of natural gas in interstate commerce, described in all of the applications, and amendments thereto in these consolidated proceedings, subject to the conditions specified for Wind Gap Division of Bangor Gas Company, and The Hughesville Division of Jersey Shore Gas & Heating Company, and all subject to the jurisdiction of the Commission.

(B) The certificates issued in Paragraph (A) above shall be void and without force or effect unless accepted in writing thirty days from the date on which this order becomes effective, and in accordance with the provisions of paragraph (a) of Section 157.20 of the Commission's Regulations under the Natural Gas Act.

SAMUEL W. JENSCH,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

ORGANIZATION OF COMMISSION—DELEGATION OF AUTHORITY, DOCKET NO. R-214

ORDER NO. 245

ADOPTING REVISED STATEMENT OF ORGANIZATION

(Issued April 30, 1962)*

On April 29, 1959, the Commission, acting pursuant to Section 3(a)(1) of the Administrative Procedure Act (60 Stat. 238; 5 U.S.C. 1002), issued Order No. 213, *Statement of Organization* (21 FPC 601, 24 F.R. 3654), which described the then current central and field organization, including delegations of final authority and other information required by the Administrative Procedure Act.

Since the issuance of Order No. 213, the Commission has reorganized its staff in numerous respects and has issued additional delegations of final authority.

It thus appears that it is desirable and in the public interest to issue a revised statement describing our current organization and cumulating currently effective delegations of final authority.

The Commission finds:

The amendment to its general rules adopted hereby involves matters of agency organization and procedure which do not require notice and hearing under Section 4(a) of the Administrative Procedure Act and good cause exists to make the amendment effective forthwith. *The Commission*, acting pursuant to authority granted by Section 309 of the Federal Power Act and Section 16 of the Natural Gas Act (16 U.S.C. 825h; 15 U.S.C. 7170) and in accordance with Section 3 of the Administrative Procedure Act (5 U.S.C. 1002), *orders:*

(A) Subchapter A, General Rules, Chapter I of Title 18 of the Code of Federal Regulations, is amended by adding a new Part 3 to read as set forth in the attachment hereto:

*Published in Federal Register on May 4, 1962 (27 F.R. 4276).

(B) Order No. 213, issued April 29, 1959 (21 FPC 601, 24 F.R. 3654), is hereby superseded.

(C) The new Part 3 prescribed hereby shall become effective upon the issuance of this order.

(D) The Secretary shall cause prompt publication of this order to be made in the Federal Register.

ATTACHMENT

SUBCHAPTER A—GENERAL RULES

* * *

PART 3—ORGANIZATION

Sec.
3.1 Purpose.
3.2 Nature and responsibilities of Commission.
3.3 Functions.
3.4 Organization.
3.5 Delegations of Final Authority.
3.6 Offices of Commission; information and submittals.

§ 3.1 *Purpose.* This part describes the central and field organization of the Federal Power Commission, including delegations of final authority and the established places at which, and methods whereby, the public may secure information or make submittals or requests. The statement of organization adopted by the Commission in its Order No. 213, dated April 29, 1959 (24 F.R. 3654–3656), is hereby superseded.

§ 3.2 *Nature and responsibilities of the Commission.* The Federal Power Commission, established as an independent agency of the Federal Government by the Act of June 23, 1930 (46 Stat. 797), is responsible for: Administration and enforcement of the Federal Power Act and the Natural Gas Act; certain duties under the Flood Control Act of 1938 and subsequent Flood Control Acts, the River and Harbor Act of 1945 and subsequent River and Harbor Acts, and a number of other statutes, pertaining principally to Federal power projects; and certain functions pursuant to Executive Order 10485 (18 F.R. 5397, 3 CFR 1948–1953 Comp., p. 970) relating to electric power and natural gas facilities located on the borders of the United States.

§ 3.3 *Functions.* The principal functions of the Commission are:

(a) *Hydroelectric Resources.* Licensing hydroelectric power projects on waters over which the Congress has jurisdiction, or on Federal lands, or utilizing surplus water or water power from Federal dams; determining original costs and making analysis of reserve requirements of hydroelectric licensees; collecting and recording data concerning developed and undeveloped water power resources of the Nation; making surveys and studies, including power market surveys, of the requirements for comprehensive development of river basins for hydroelectric power and other purposes; analyzing plans for and making recommendations concerning hydroelectric power installations at Federal river development projects; and making determinations of payments for benefits provided by headwater improvements to downstream power projects.

(b) *Electric energy.* Regulating the rates, accounts, depreciation practices, security issues, property dispositions, mergers, consolidations, exportation of electric energy and border facilities therefor, interconnections, and coordination of facilities, of public utilities engaged in the transmission and sale for resale of electric energy in interstate commerce; gathering, compiling, and publishing statistical and other information concerning electric power and the electric

power industry in the United States; and analyzing and serving as the central source of information concerning national and regional power supply and requirements.

(c) *Natural gas.* Issuing certificates of public convenience and necessity for the construction and operation of facilities for the transportation or sale for resale of natural gas in interstate commerce; granting import, export, and border permits; ordering extensions of facilities or service; authorizing abandonment of such facilities or service; regulating the rates, accounts, and depreciation practices of certificated natural gas companies; compiling and publishing statistical and other information concerning the natural gas industry in the United States. These activities embrace full consideration of all aspects of the public interest in balancing natural gas exploration, conservation, supply, interstate transport, storage and ultimate consumption on a national scope.

(d) *Federal power rates.* Allocating costs, and approving accounts, rates, and related matters, for certain Federal hydroelectric power projects.

§ 3.4 *Organization.* The Federal Power Commission as an agency of Government consists of: The five-man Commission; the immediate offices of the individual Commissioners; the Chairman as executive and administrative head of the agency; the Executive Director; and the technical and administrative staff.

(a) *The Commission.* Except as provided below with respect to executive and administrative functions, the Commission is responsible for all plans, programs, and actions of the agency. The members of the Commission are appointed by the President, by and with the consent of the Senate. The Chairman is designated by the President. A Vice Chairman is elected annually by the members of the Commission. Any three members of the Commission constitute a quorum for the transaction of business.

(b) *Commissioners' offices.* Each Commissioner's immediate office is subject to his exclusive jurisdiction. Persons employed there regularly and full time are selected by him, perform such duties as he may assign, and are responsible to him alone.

(c) *Chairman.* The Chairman is the principal executive officer of the agency, responsible for all executive and administrative functions except those reserved to the Commission by Reorganization Plan No. 9 of 1950 (64 Stat. 1265).

(d) *Executive Director.* The Executive Director, under the direction of the Commission on substantive matters, and as the Chairman's delegate on executive and administrative matters, is responsible for and takes action to insure the effectiveness and efficiency of staff operations.

(e) *The Staff.* The Commission's staff is comprised of eleven bureaus and offices, as follows:

(1) *The Bureau of Natural Gas,* responsible for all staff activities pertaining to the natural gas industry, except: Legal matters; the uniform systems of accounts; original cost and reclassification studies; financial and related statistical matters, including rate-of-return studies; and other matters responsibility for which is assigned to other elements of the staff. The Bureau consists of the Office of the Chief, the Pipeline Division, the Producer Division, the Planning and Control Divison and a field office in Houston, Texas (under the administrative control of the Planning and Control Division). The field office performs work assigned by the Pipeline and Producer Divisions including field audits, engineering, geological, and accounting investigations arising from the production and transportation of natural gas for sale in interstate commerce for resale.

(2) *The Bureau of Power*, responsible for all staff activities pertaining to water resources, hydroelectric power, and the electric power industry, except: Legal, accounting, financial, and related statistical matters; and other matters responsibility for which is assigned to other elements of the staff. The Bureau is divided into a headquarters office at Washington and five regional offices. The headquarters office consists of the Chief of the Bureau of Power and his immediate staff, a Division of Licensed Projects, a Division of Electric Resources and Requirements, and a Division of River Basins. The Regional offices, at New York, Atlanta, Chicago, Fort Worth, and San Francisco, are responsible within their respective geographic areas for Bureau functions which can be done most effectively and efficiently in the field, including field investigations and studies, consultations, and inspections.

(3) *The Office of Accounting and Finance*, responsible for all staff activities pertaining to accounting, financial and related statistical matters (including rate-of-return studies), except: Legal matters; accounting investigations relating to rates and charges for electric power and natural gas; statistics on hydroelectric resources, power systems, power supply and requirements, power production and capacity, fuel consumption and stocks, electric utility systems loads, and electric plant construction costs and production expenses; and other matters responsibility for which is assigned to other elements of the staff. The office consists of the Chief Accountant and his immediate staff, a Division of Accounts and a Division of Finance and Statistics. The Division of Accounts includes field units with headquarters in San Francisco, California, and Houston, Texas. The Chief Accountant, in addition to his duties as head of the office, has personal responsibility for the overall correlation and adequacy of the accounting and related functions of all bureaus and offices of the staff.

(4) *The Office of the General Counsel*, responsible for the legal phases of all Commission functions, including litigation in the courts.

(5) *The Office of the Secretary*, responsible for the secretariat functions of the Commission, including the duties of the Secretary as set forth in this chapter, and for action on behalf of the Commission pursuant to the delegations of final authority described in § 3.5 hereof.

(6) *The Office of Hearing Examiners*, responsible for discharging the functions and exercising the powers of presiding officers in hearings, in accordance with the provisions of Sections 7 and 8 of the Administrative Procedure Act and § 1.27 of this chapter.

(7) *The Office of Special Assistants to the Commission*, responsible for assisting the Commission in the preparation of opinions, orders, and other legal documents, and for analyzing exceptions, preparing summaries of facts and issues, and performing related duties, as assigned. The Office is under the direction of the Commission or individual members thereof on substantive matters, but is under the administrative supervision of the General Counsel.

(8) *The Office of Economics*, responsible for obtaining and evaluating economic and statistical information necessary in the administration of the Federal Power Act and the Natural Gas Act; appraising the economic implications of proposed policies, and assisting the Commission in the formulation of economic policies required in the administration of the Federal Power Act and the Natural Gas Act.

(9) *The Office of Administration*, responsible on a Commission-wide basis for budget and fiscal activities, general administrative services, and management services, including administration of the automatic data processing program and services. The Office consists of the Director of Administration and his

immediate office, the Division of Budget and Finance, the Division of General Services, and the Division of Management Assistance.

(10) *The Office of Personnel*, responsible for the Commission's personnel management activities and the personnel security program.

(11) *The Office of Public Information*, responsible for the public information activities of the agency, including issuance of press releases, sale and distribution of publications, and public reference service.

§ 3.5 *Delegations of Final Authority.* The Commission has authorized:

(a) The Secretary, or in his absence, the Acting Secretary, to:

(1) Sign official correspondence on behalf of the Commission.

(2) Prescribe the time for filing by electric utilities, licensees, natural gas companies, and other persons, answers to complaints, petitions, motions, and other pleadings and documents, provided that no answers shall be required to be filed in less than ten days after the date of service of the pleading or document to which answer is made.

(3) Schedule hearings and issue notices thereof.

(4) Accept for filing, subject to the order of the Commission, notices of intervention and petitions to intervene by State commissions and Federal agencies.

(5) Reject petitions to intervene filed in a period later than ten days next preceding the date the matter is set for hearing, unless good cause is shown for the late filing.

(6) Consolidate proceedings for hearing simultaneously on a record, and sever proceedings which have been consolidated.

(7) Deny motions or requests for extensions of time filed later than the time prescribed by the rules unless good cause is shown for the late filing.

(8) Reject pleadings, briefs, and other documents filed later than the time prescribed by an order, rule, or regulation of the Commission unless good cause is shown for the late filing.

(9) Waive requirements of the Commission's rules and regulations, when consistent with the public interest in a particular case.

(10) Pass upon questions of extending time for electric public utilities, licensees, natural gas companies, and other persons to file required reports, data, and information and to do other acts required or allowed to be done at or within a specific time by any rule, regulation, license, permit, certificate, or order of the Commission, not to exceed in any event an extension of six months beyond the time or period originally prescribed.

(11) Accept service of process upon behalf of the Commission.

(12) Accept for filing bonds or agreements and undertakings submitted in rate suspension proceedings when they are found to be satisfactory.

(13) Take the following action on rate schedule and certificate filings submitted by independent producer natural gas companies prior to issuance on September 27, 1956, of Order No. 190 (16 FPC 492, 21 F.R. 7616, October 4, 1956) involving non-signatory parties or percentage sales which may be found to be in conflict with said order: Vacate the orders previously issued granting certificates of public convenience and necessity, and cancel the prior acceptances of, and reject, the related rate schedules, after the applicant or filing party has been advised that such action is contemplated and given 15 days for filing a response to the letter of notification, or upon request of an independent producer who is a non-operating signatory party, cancel the prior acceptance of and reject the rate schedules where certificate applications have been or are concurrently being rejected; advise the filing party of final action by appropriate letter.

(14) Take the following actions on certificate and rate schedule filings of independent producers, where the sales involved are not of an interstate char-

acter, or where proposed interstate sales were never made: (i) Upon request of the filing party, vacate the order previously issued granting a certificate of public convenience and necessity; and (ii) cancel the prior acceptance of and permit withdrawal of the related rate schedule upon request of the filing party or where the certificate application is concurrently being or has been previously withdrawn.

(15) Publish Notice of Land Withdrawals under Section 24 of the Federal Power Act.

(16) Approve, with respect to particular parcels of land within the project area of a licensed water-power project, the conveyance by the licensee to another legal entity of an interest therein for use for a non-project purpose, subject to the right of the licensee, its successors and assigns to use the land for all project purposes contemplated by the license for the project.

(17) Accept for filing initial rate schedules and rate changes submitted by natural gas companies and electric utilities where no rate increase other than for state gathering, production, or similar tax is involved and where no waiver of statutory notice is required and advise the filing party of such acceptance, the designation of the rate schedule and effective date thereof.

(18) Issue notices of applications filed under the Federal Power and Natural Gas Acts, fixing the time for filing comments, protests or petitions to intervene and schedule hearings on such applications when appropriate or required by law.

(19) Accept for filing rate schedules and supplements thereto, if any, submitted in compliance with conditions in certificates of public convenience and necessity, both temporary and permanent, issued under Section 7 of the Natural Gas Act, when they meet the requirements prescribed by such certificates and advise the filing party of such acceptance, the designation of the rate schedule and effective date thereof.

(20) Pass upon, when appropriate, applications, petitions, and requests submitted under General Instruction No. 12 of the Uniform System of Accounts prescribed for natural gas companies for approval to group certain gathering systems, or certain transmission mains, or certain compressor stations for the purpose of complying with that portion of General Instructions No. 12 (formerly covered by General Instruction No. 11, prior to January 1, 1961) requiring a segregation of the cost of operating and maintaining each plant.

(21) Accept for filing amendments to agreements and contracts or rate schedules submitted in compliance with Commission orders accepting offers of rate settlements if such filings are in satisfactory compliance with such orders.

(22) Issue notices requiring that the rates under suspension be charged where a motion to make such a rate effective is filed by the independent producer concerned, and to accept for filing the bond or agreement and undertaking when deemed to be satisfactory.

(23) Reject a rate filing in accordance with Section 1.14(a)(2) of this chapter, if it fails to comply with applicable statutory requirements, Commission rules or regulations, or Commission orders.

(24) Accept for filing data and reports required by Commission orders and presiding examiner's initial decisions when such filings are considered to be in satisfactory compliance with the orders or decisions, and when appropriate, to notify the filing party of such acceptance.

(b) The *Chief Accountant*, or in his absence the Acting Chief, to issue interpretations of the Uniform Systems of Accounts for Public Utilities, Licensees, and Natural Gas Companies.

(c) *Regional Engineers* of the Bureau of Power, or, in the absence of a regional engineer, the Acting Regional Engineer, to grant 30-day extensions of time for filing Power System Statements (Forms 12, 12A, etc.).

(d) *The Chief Examiner*, and the examiners designated to preside at hearings, to exercise the functions and powers stated and enumerated for presiding officers in the Commission's Rules of Practice and Procedure, particularly Section 1.27 (18 CFR 1.27).

§ 3.6 *Offices of the Commission; information and submittals.*

(a) *Headquarters* of the Federal Power Commission are in the General Accounting Office Building, 441 G Street NW., Washington, D.C. Information concerning matters for which the Commission is responsible may be obtained in person at that office, or by written request addressed to the Federal Power Commission, Washington 25, D.C. All formal requests, filings, and submittals should be addressed to the principal office of the Commission, pursuant to 18 CFR 1.1(g).

(b) *Regional offices* of the Bureau of Power, to which should be submitted all prescribed Power System Statements, and from which may be obtained information concerning power matters assigned to them, are located as follows:

(1) New York Regional Office, at 346 Broadway, New York 13, N.Y., serving: Connecticut; Delaware; District of Columbia; part of Kentucky; Maine; Maryland; Massachusetts; New Hampshire; New Jersey; New York; part of Ohio; Pennsylvania; Rhode Island; Vermont; and parts of Virginia and West Virginia.

(2) Atlanta Regional Office, at Peachtree-Seventh Building, 50 Seventh Street NE., Atlanta 23, Georgia, serving: Alabama; Florida; Georgia; parts of Kentucky and Mississippi; North Carolina; South Carolina; Tennessee; and parts of Virginia and West Virginia.

(3) Chicago Regional Office, in the United States Custom House, 610 South Canal Street, Chicago 7, Illinois, serving: Illinois; Indiana; Iowa; part of Kansas; Michigan; Minnesota; parts of Missouri, Montana, and Nebraska; North Dakota; parts of Ohio and South Dakota; Wisconsin; and part of Wyoming.

(4) Fort Worth Regional Office, at 289 University Plaza Building, 100 North University Drive, Fort Worth 7, Texas, serving: Arkansas; Colorado; part of Kansas; Louisiana; parts of Mississippi, Missouri, Nebraska and New Mexico; Oklahoma; part of South Dakota; Texas; and part of Wyoming.

(5) San Francisco Regional Office, in the United States Custom House, 555 Battery Street, San Francisco 11, California, serving: Alaska; Arizona; California; Hawaii; Idaho; part of Montana; Nevada; part of New Mexico; Oregon; Utah; Washington; and part of Wyoming.

(c) *Public files and records*, described in 18 CFR 1.36, are available for public inspection in the Office of Public Information at Agency headquarters.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

TRANSWESTERN PIPELINE COMPANY, DOCKET NO. G-20464

ORDER GRANTING PETITION TO REOPEN PROCEEDING FOR THE PURPOSE OF TAKING ADDITIONAL EVIDENCE

(Issued April 30, 1962)

On April 11, 1962, Transwestern Pipeline Company (Transwestern) filed a petition, as supplemented by a telegram as of the same date,* requesting that the

*The telegram requests that "a date for rehearing in the reopened proceeding not be fixed until such time as Transwestern has filed a certificate application in connection with its proposed sale of gas to Cities Service Gas Company and a hearing date has been fixed on such application."

above-captioned Section 7(c) proceeding be reopened for the purpose of taking additional evidence. This proceeding has been heard and, on February 27, 1962, the presiding examiner issued his decision denying Transwestern's application for a certificate of public convenience and necessity. The examiner found that Transwestern had not made a showing in the record in this case, especially as to markets and economic feasibility, of the necessity at this time or within the reasonably foreseeable future for the additional supplies of natural gas which would be made available by the field facilities proposed in this proceeding. The time within which to file exceptions to the examiner's decision has been extended to and including May 14, 1962.

On April 12, 1962, the Public Utility Commission of the State of California filed a telegraphic answer not objecting to the petition to reopen. On April 16, 1962, the Pacific Lighting Companies (Pacific Lighting Gas Supply Company, Southern California Gas Company, and Southern Counties Gas Company of California) filed an answer objecting to the reopening unless the hearings in the reopened proceedings are postponed for consolidation with the application to be filed by Transwestern for authorization to make additional sales.

Transwestern asserts that subsequent to the closing of the record and the issuance of the examiner's decision in this case, material changes occurred in its market situation which remove any question as to the sufficiency of its market and the economic feasibility of the proposed facilities. Transwestern alleges that its sales of natural gas to Pacific Lighting Gas Supply Company (Gas Supply) increased substantially in the last six months and that it recently entered into a letter agreement with Cities Service Gas Company (Cities Service) whereby it proposes to sell 100,000 Mcf of natural gas per day to Cities Service, commencing on January 1, 1964, and increasing to 200,000 Mcf per day on or before January 1, 1966. Transwestern seeks to adduce additional evidence to support these contentions and also requests to present evidence to show that its construction of certain field facilities, involved in this proceeding, was not a willful violation of Section 7(c) of the Natural Gas Act.

Although in this proceeding Transwestern apparently did not rely on a showing of new markets or additional sales, the presiding examiner made it very clear that Transwestern would not be foreclosed from renewing its application at some future time when, and if, it could demonstrate a need for the additional supplies of natural gas. In view of this, we believe that the alleged change in Transwestern's market situation is sufficient cause for reopening this proceeding. Since the proceeding will be opened and in order to give it every opportunity to explain the construction of the field facilities not covered by the temporary certificate, Transwestern will also be permitted to present evidence to show that there has been no violation of Section 7(c).

The date of the further hearings in this proceeding will be fixed by a future notice after Transwestern has filed an application for a certificate of public convenience and necessity in connection with its proposed sale of gas to Cities Service.

The Commission finds:

Good and sufficient cause has been alleged for the granting of the petition to reopen proceeding for the purpose of taking additional evidence filed by Transwestern Pipeline Company.

The Commission orders:

The petition to reopen proceeding for the purpose of taking additional evidence, filed by Transwestern Pipeline Company, is granted.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

UNITED STATES DEPARTMENT OF THE INTERIOR, SOUTHWESTERN POWER ADMINISTRATION, DOCKET NO. E-6975

ORDER CONFIRMING AND APPROVING RATES AND CHARGES

(Issued April 30, 1962)

Pursuant to the Flood Control Act of 1944 (58 Stat. 887), the Assistant Secretary of the Interior (Secretary) on behalf of the Southwestern Power Administration (SWPA) on November 3, 1961, submitted for confirmation and approval the rates and conditions of service for the sale of "Hydro Peaking Power" and "Seasonal Peaking Power" service set forth in a proposed new rate schedule, designated as P-2. Service under the new rate schedule would be available to wholesale power customers who contract for the purchase of such power delivered from the 138-161 kv main grid transmission system owned by, or made available through contract to, SWPA. Approval was requested for a period from the date of the Commission's action until July 1, 1967.

On January 17, 1962, the Secretary submitted a revision of the proposed Rate Schedule P-2 and requested that it be substituted for the proposed rate schedule submitted November 3, 1961. The revised rate schedule specified the amount of energy to accompany the "hydro and seasonal peaking power" service.

SWPA is an agency of the United States established in the Department of the Interior to execute the purposes of the Flood Control Act of 1944 (Flood Control Act) with respect to the disposition of electric power and energy made available to the Secretary of the Interior from the reservoir projects under the control of the Department of the Army in the area comprising all of Arkansas and Louisiana and portions of Missouri, Kansas, Texas and Oklahoma. At the present time, the Department of the Army has constructed and is operating nine such projects in this area. The installed capacity of these projects, including two generating units under construction at the Bull Shoals project is 881,000 kilowatts (kw). In addition, SWPA has leased from certain REA generating and transmission cooperatives, under long-term agreements, the output of three steam-electric generating plants, with a total capacity of 85,000 kw.

These Army projects and REA steam plants, with the exception of the isolated Narrows and Whitney projects located in Arkansas and Texas, respectively, and the interconnecting transmission lines owned or leased by SWPA and others leased from the REA generating and transmission cooperatives in the area compose an integrated system.

The proposed Rate Schedule P-2 would be applicable to wholesale power customers who, by contract, purchase "Hydro Peaking Power" service and/or "Seasonal Peaking Power" service. For such service, the customer would be guaranteed a minimum of 1200 kilowatt hours (kwh) per kw of demand each contract year. This is equivalent to an annual load factor of 13.7 percent. The service would be from, and at the voltage of, the 138 kv or the 161 kv transmission facilities owned by or available to SWPA, or at lower or intermediate voltages from substations directly connected to such transmission facilities. The demand charge would be $14.40 per year per kw of "Hydro and/or Seasonal Peaking Power," payable at the rate of $1.20 per month per kw. The energy charge would be 2.0 mills per kwh.

The rates and conditions of service in the proposed Rate Schedule P–2 are consistent with those in SWPA's approved Rate Schedule SP which is a schedule of wholesale rates for special peaking power service. Under Rate Schedule SP, SWPA supplies 1200 kwh of energy per kw of contract demand during each fiscal year. The energy charge is 2.0 mills per kwh. The basic demand charge is $19.20 per year per kw of contract demand but a discount of $4.80 per kw is allowed if the delivery of power is made from, and at the voltage of, the 138 kv or 161 kv transmission facilities owned or leased by SWPA. Thus, the demand charge is the same, $14.40 per year per kw, as the demand charge proposed in Rate Schedule P–2 when conditions of service are the same.

SWPA is negotiating two new contracts for the sale of 478,000 kw of power at the rates specified in the proposed new Rate Schedule P–2. One of the proposed contracts is with Kansas City Power & Light Company, Missouri Public Service Company and The Empire District Electric Company (Companies). The other is with the Associated Electric Cooperative, Inc. (Associated). Associated is an electric cooperative corporation, organized under the laws of the State of Missouri to engage in the purchase, generation, interchange, transmission, and supply of electric power and energy for its member cooperatives, referred to in the contract as the "Federated Cooperatives," as follows:

Central Electric Power Cooperative, Jefferson City, Missouri.
KAMO Electric Cooperative, Inc., Vinita, Oklahoma.
M&A Electric Cooperative, Poplar Bluff, Missouri.
Northeast Missouri Electric Power Cooperative, Palmyra, Missouri.
N.W. Electric Power Cooperative, Inc., Cameron, Missouri.
Sho-Me Power Corporation, Marshfield, Missouri.

In addition to the afore-mentioned contracts, Associated and the Companies are negotiating an integration contract whereby they would interconnect their transmission systems and operate as a single integrated system, so as to pool and utilize the hydroelectric power and energy available to them under the contracts between SWPA and Associated and SWPA and Companies.

Under the contract with the Companies, SWPA would sell "Seasonal Peaking Power" in amounts graduating in yearly contract amounts from 12,000 kw at the start of service in 1962 to 190,000 kw beginning in June 1965 and thereafter for the duration of the contract which terminates May 31, 1985. During periods when the total generating capability of the Bull Shoals and Table Rock projects is less than the total nameplate rating of their installed capacity, SWPA would be permitted to reduce the above amounts of Seasonal Peaking Power, except during the months of June, July, August, and September. SWPA would sell the Companies 1200 kwh of energy per kw of Seasonal Peaking Power during each contract year.

Under the contract with Associated, SWPA would sell "Hydro Peaking Power" in amounts graduating in yearly contract amounts from 125,000 kw at the start of service in 1962 to 288,000 kw beginning in June 1965 and thereafter for the duration of the contract which terminates May 31, 2000. The contract specified the minimum and maximum amounts of energy which Associated would be required to purchase and SWPA would be required to sell. The minimum energy specified is 1,200 kwh per kw of "Hydro Peaking Power" during each contract year. The maximum energy to be sold is computed by a formula which takes into account several factors, including the amount of energy generated at the

Bull Shoals and Table Rock projects and the amount of energy SWPA is obligated to deliver the Companies.

The contract with Associated, in addition to providing for the sale of power by SWPA to Associated, covers services to be provided by Associated to SWPA. These services include among others, providing SWPA with transmission service over the Associated 161 kv System and providing SWPA with reserve generating capacity from the Associated System. For the total services to be supplied, SWPA would make a credit payment to Associated of $4,140,000 per year, increasing to $4,656,000 per year upon completion of construction of certain transmission lines and substations by Associated.

In support of the proposed marketing arrangements, SWPA presented a study with estimates of annual costs and revenues assuming, first, a continuation of present contractual arrangements for marketing power in the Missouri area and, second, contractual arrangements for marketing power under the new contracts which are being negotiated with Associated and the Companies. In each case, SWPA assumed the sale of 540,000 kw of capacity and associated energy. For the present marketing arrangements, the power was assumed to be sold under existing Rate Schedules P–1, SP, F–1, and EE. The contractual costs were those that would be incurred under existing lease and service contracts with six G&T Cooperatives, plus allowance for losses and reserves. Under the proposed marketing arrangements the power was assumed to be sold under proposed Rate Schedule P–2 and existing Rate Schedule F–1. The contractual costs were those that would be incurred under the proposed contract with Associated plus certain firming costs. Costs common under both assumptions, such as hydro plant operation and maintenance costs, were omitted. It is believed that these estimates by SWPA represent a reasonable financial comparison of present and proposed marketing arrangements in the Missouri area. The results of this study are as follows:

	Present arrangements	Proposed arrangements
Annual revenues	$12,967,000	$10,753,000
Annual costs	9,863,000	5,877,000
Net revenues	3,104,000	4,876,000

The above comparison indicates that SWPA's proposed new marketing arrangements for the Missouri area would provide an increased annual benefit to SWPA of $1,772,000 when compared to a continuation of present marketing arrangements.

Notice of the request for the approval of the proposed rate schedule was sent to State officials, other interested parties and was published in the Federal Register on November 18, 1961 (26 F.R. 10818), stating that any comments or suggestions should be submitted on or before December 4, 1961. None were received.

Although the action taken herein is confined to the confirmation and approval of the proposed Rate Schedule P–2 pursuant to the provisions of Section 5 of the 1944 Flood Control Act, we note that the contracts discussed above, pursuant to which Companies and Associated propose to render service and make sales,

will be subject to the rate schedule filing requirements of Section 205[1] of the Federal Power Act to the extent that the facilities utilized to render the services are subject to the jurisdiction of the Commission.[2]

The Commission finds:

The proposed rate schedule for the sale of "Hydro Peaking Power Service" and "Seasonal Peaking Power Service" and accompanying energy in SWPA's service area designated as SWPA Rate Schedule P–2, for a period beginning with the date of this order and expiring July 1, 1967, will not be inconsistent with the provisions of the Flood Control Act of 1944.

The Commission orders:

The proposed SWPA Rate Schedule P–2 filed November 3, 1961, as modified by filing of January 17, 1962, all as set forth above is confirmed and approved for a period beginning with the date of the issuance of this order and terminating July 1, 1967.

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[1] Subsection 205(c) of the Federal Power Act provides:

"Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in the convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services."

[2] Previously, the Commission found and determined each of the above Companies to be "public utilities". See *Interstate Power Company, Kansas City Power & Light Company,* 17 FPC 663, 665; *Missouri Public Service Co., The Empire District Electric Co.,* 13 FPC 745, 746–7. Associated, being a corporation within the meaning of Section 3(3) of the Federal Power Act, comes within the definition of "person" in Section 3(4) of the Act. A "person" who "owns or operates facilities subject to the jurisdiction of the Commission" (Sec. 201(e)) has the status of a "public utility" under Part II.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

DUNLAP OIL CORPORATION, DOCKET NO. G–19935

ORDER ACCEPTING OFFER OF SETTLEMENT AND TERMINATING PROCEEDING

(Issued May 1, 1962)

On March 29, 1962, Dunlap Oil Corporation (Dunlap) submitted, in accordance with the provisions of Section 1.18(e) of the Commission's Rules of Practice and Procedure, an offer of settlement of the suspension proceeding in Docket No. G–19935 involving its jurisdictional sale of natural gas to Tennessee Gas Transmission Company (Tennessee Gas) in the Seeligson Field, Jim Wells County, Texas (Railroad Commission District No. 4).

In the offer, Dunlap proposes to reduce the increased rate[1] of 15.0952¢ per Mcf, which became effective subject to refund on April 1, 1960, to a settlement rate of 14.6¢ per Mcf at 14.65 psia. Under the terms of the settlement offer the favored-nation and price redetermination provisions are to be eliminated from the rate schedule and the tax reimbursement clause is to be revised to provide for reimbursement of three-fourths of any increase in tax occurring after November 1, 1959. The 14.6¢ per Mcf settlement rate, as proposed, would take effect as of April 1, 1960 and continue until November 1, 1964, with a 1.0¢ per Mcf escalation on November 1, 1964 and at five-year intervals thereafter through November 1, 1974.

Tennessee Gas has joined in the Offer of Settlement and approves the proposed contract amendment. No objections to the proposed settlement have been received in this proceeding.

Since the proposed rate of 14.6 cents per Mcf at 14.65 psia is acceptable under the provisions of the Second Amendment to the Commission's Statement of General Policy No. 61–1 [18 CFR, Chapter I, Part 2, Section 2.56] issued December 20, 1960, for jurisdictional sales of natural gas for Texas Railroad Commission District No. 4, it appears that the public interest will best be served by accepting Dunlap's proposed settlement as herein provided.

However, we desire to make it clear that acceptance of this Offer of Settlement shall not be construed as approval of any future increased rates proposed by Dunlap under the periodic escalation provisions or otherwise.

The Commission finds:

The proposed settlement of this rate proceeding on the basis described herein, as more fully set forth in the Offer of Settlement filed by Dunlap with the Commission on March 29, 1962, is in the public interest and appropriate to carry out the provisions of the Natural Gas Act and should be approved by the Commission and made effective as hereinafter ordered.

The Commission orders:

(A) The Offer of Settlement filed by Dunlap with the Commission on March 29, 1962, in Docket No. G–19935, is hereby approved in accordance with the provisions of this order.

(B) Within 30 days from the date of issuance of this order, Dunlap shall file, subject to approval of the Commission, a supplement to the subject rate schedule reflecting the provisions of the settlement offer herein approved, and shall refund

[1] Designated Supplement No. 1 to Dunlap's FPC Gas Rate Schedule No. 2.

to Tennessee Gas, with interest at the rate of 7 percent per annum to date of refund, all amounts collected for gas sold on and after April 1, 1960, in excess of the settlement rate of 14.6¢ per Mcf. Within 45 days from the date of issuance of this order Dunlap shall report to the Commission, in writing and under oath, the amount of refunds paid to Tennessee Gas, showing the calculation thereof including the separate amounts of principal and interest; and Dunlap shall file an acknowledgment signed by a responsible officer of Tennessee Gas that said amounts satisfy the obligations under the settlement offer.

(C) Upon full compliance by Dunlap with all the terms and conditions of this proceeding shall be terminated.

(D) The acceptance of this Offer of Settlement is without prejudice to any findings or determinations that may be made in any proceeding now pending or hereafter instituted by or against Dunlap.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. CP62-14; THE MANUFACTURERS LIGHT & HEAT COMPANY, DOCKET NO. CP61-155

ORDER FIXING DATE FOR HEARING AND DEFINING ISSUES

(Issued May 1, 1962)

On March 22, 1962, Tennessee Gas Transmission Company (Tennessee) filed in the above-entitled proceeding a motion for reconsideration or in the alternative for prompt hearing with defined issues.

Tennessee alleges that it filed an application in the above-captioned proceeding for authorization to transfer the deliveries of 35,000 Mcf of natural gas per day that is presently being delivered to United Fuel Gas Company (United) in Tennessee's Eastern Rate Zone to The Manufacturers Light & Heat Company (Manufacturers) for the account of United in Tennessee's Northern Rate Zone. Tennessee proposes that its transfer of deliveries will take place during the six-month period commencing on November 1, 1961, and ending on April 30, 1962, and for each six-month period thereafter that commences on November 1 and ends on April 30, for the term of years coextensive with the term of the presently effective gas sales contract between Tennessee and United.

Tennessee alleges that pursuant to temporary authorization issued August 18, 1961, to transfer said deliveries as proposed in its application, Tennessee and United entered into a gas sales contract dated October 10, 1961, which, Tennessee alleges, provides for "the transfer of deliveries as proposed and temporarily authorized for a term of years ending on November 1, 1979." Tennessee further alleges that this contract was permitted to take effect on November 1, 1961, the date upon which the deliveries of natural gas to Manufacturers for the account of United was commenced.

Tennessee alleges that at the hearing hereon held December 18, 1961, the only issue raised was "that of the proper sharing, between United and Manufacturers, of the increased rate which United pays to Tennessee for deliveries made in Tennessee's Northern Rate Zone over the rate United pays for deliveries in Tennessee's Eastern Rate Zone." No party, it is alleged, raised any question as to the term of the transfer. Tennessee further alleges that all parties

stipulated that: (1) Manufacturers should reimburse United for the net amount of such increased costs; (2) a condition with respect to such reimbursement should be included in the order issuing a certificate of public convenience and necessity to Tennessee and Manufacturers; (3) on or before January 2, 1962, Staff Counsel would serve upon all parties a copy of a draft of the proposed order containing such reimbursement condition; and, (4) the hearing should reconvene on January 15, 1962, for the purpose of offering the parties an opportunity to comment on the proposed order and to submit same to the Examiner.

Tennessee states that at the reconvened hearing no party objected to the provisions of the proposed order; that subsequent to the conclusion of the hearing the Pennsylvania Public Utility Commission requested the Commission to modify the proposed order so as to provide that United and Manufacturers would share the additional zone differential charges from Tennessee in proportion to their estimated costs, as if Manufacturers had constructed the facilities which were originally proposed, but which were rendered unnecessary by the proposed transfer of deliveries. It is pointed out that the Pennsylvania Commisssion did not urge a reopening nor raise a question as to the term of the transfer service.

Tennessee asserts that unless such transfer is authorized on a long-term basis as proposed, Manufacturers will still be required to construct additional duplicate facilities.

The Commission in its order of February 20, 1962, said that it appeared to the Commission that there was a serious question as to whether the granting of the applications would not place Manufacturers in the position of making payments to United for a service which United did not render and that it would not be appropriate for United to make a charge for a service it did not render.

Tennessee has submitted no new facts which would warrant issuance of permanent authorization to it at this time. However, for the purpose of clarification of the issues, the Commission will indicate in the ordering paragraph herein the issues to be tried at the hearing to determine the propriety of the charge to be made by United.

The Commission finds:

Good cause has been shown for the granting of Tennessee's motion for reconsideration or in the alternative for prompt hearing with defined issues to the extent that the proceeding will be set for hearing and the issues defined as hereinafter ordered.

The Commission orders:

The above-docketed proceedings be and the same are hereby set for further hearing on June 4, 1962 and the issues to be developed upon such hearing shall include the following:

(1) Does United in fact render a service for which it should be reimbursed? (2) If United renders a service, is the proposed basis of reimbursement just and reasonable? (3) Does the arrangement properly fall within the scope of a Volume No. 2 tariff filing, or is it in conflict with Section 154.52 of the Commission's Regulations? (4) Does the arrangement improve the reliability of service and offer additional flexibility in operating techniques to the integrated Columbia System? (5) Does the arrangement represent an accommodation to the Columbia System, resulting in benefiting the System as a whole, rather than primarily benefiting Manufacturers?

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

THE WASHINGTON WATER POWER COMPANY, PROJECT NO. 2058

ORDER APPROVING REVISED PROJECT EXHIBIT

(Issued May 2, 1962)

Application was filed on July 1, 1957, and supplemented on March 19, 1962, by The Washington Water Power Company, licensee for major Project No. 2058, to exclude from that project lands necessary for the operation of the licensee's licensed Project No. 2075, known as the Noxon Development. Filed as part of the March 19, 1962 supplement were Exhibit K, Sheet 9 of 10 (FPC No. 2058–44), revised March 7, 1962, showing the project boundary line of Project No. 2058 after deletion therefrom of the lands transferred to Project No. 2075, and Exhibit F, a tabulation of Project No. 2058 lands. Commission approval of the latter exhibit is not required.

Application to include in Project No. 2075 the lands transferred from Project No. 2058 is pending in the Commission.

The Commission finds:

(1) No lands of the United States are involved herein.

(2) The revised Exhibit K mentioned above conforms to the Commission's rules and regulations and should be approved as part of the license for Project No. 2058 and Exhibit K, Sheet 9 of 10 (FPC No. 2058–39), now part of the license for that project and which has been superseded, should be eliminated from the license for that project—all as hereinafter provided.

The Commission orders:

The revised Exhibit K referred to in finding (2) above is approved as part of the license for Project No. 2058, and the exhibit referred to in the same finding as being superseded is eliminated from the license for that project.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

GULF STATES UTILITIES COMPANY, DOCKET NO. E–7030

ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTGAGE BONDS

(Issued May 4, 1962)

Gulf States Utilities Company (Applicant), incorporated under the laws of the State of Texas and doing business in that State and the State of Louisiana, with its principal business office at Beaumont, Texas, filed an application on March 28, 1962, as amended on April 9, 18 and 26, 1962, for authorization, pursuant to Section 204 of the Federal Power Act, to issue and sell at competitive bidding $17,000,000, principal amount of First Mortgage Bonds, due 1992.

Applicant proposes to issue the Bonds under its Indenture of Mortgage, dated September 1, 1926, as supplemented and modified by twenty supplemental indentures and as to be further supplemented and modified by the Twenty-first Supplemental Indenture dated as of May 1, 1962, under which the Manufacturers Hanover Trust Company of New York is Trustee.

On or about May 9, 1962, Applicant proposes to invite sealed written bids for the purchase of the Bonds by newspaper publication and by distribution of a "Public Invitation for Bids for the Purchase of the Bonds", setting forth terms and conditions relating thereto. All bids, whether from a single bidder or group of bidders, must be in writing on the Form of Bid furnished by Applicant and must be for the purchase of the entire issuance of Bonds. Each bid must specify, among other things, (1) the interest rate of the Bonds, which shall be a multiple of ⅛th of 1%; (2) the price, exclusive of accrued interest, to be paid to Applicant for the Bonds, which shall be not less than 100% nor more than 102½% of the principal amount thereof; (3) that Applicant shall be paid the amount of the accrued interest, if any, on the Bonds from the date of the Bonds to the date of payment therefor and delivery thereof; and (4) that the initial public offering price shall not exceed the amount of the bid plus 1½% of the principal amount of the Bonds, or, alternatively, that no public offering of the Bonds for resale is intended.

Unless postponed, all bids for the purchase of the proposed issuance of Bonds must be presented to Applicant at Manufacturers Hanover Trust Company, Room A, 70 Broadway, New York 15, New York, before 12 noon, New York time, on May 21, 1962. Unless Applicant shall reject all bids (which it reserves the right to do) or shall exclude a bid or bids for reasons specified in the Public Invitation, it will accept the bid which provides the lowest cost of money to it, determined as provided in the Public Invitation. Each bid must be accompanied by a certified or official bank check or checks in the aggregate amount of $510,000.

The Commission, in an order issued on December 21, 1961 (Docket No. E–7016), authorized Applicant to issue up to $20,000,000, principal amount of short-term notes. The notes were to be issued between December 29, 1961 and December 31, 1962; they were to mature on December 31, 1962, and bear interest at the New York prime rate. According to the present application, Applicant expects to have $16,000,000, principal amount of the notes outstanding at the time Applicant receives the proceeds from the proposed issuance of Bonds.

Applicant states that the proceeds to be obtained from the proposed issuance of Bonds will be utilized to reimburse Applicant's treasury, in part, for construction expenditures heretofore made, which will enable Applicant to pay in full all of its short-term notes outstanding as of the date of issuance of the proposed Bonds, and to carry forward its current construction program, estimated to require the expenditure of $114,000,000 for the three-year period 1962 to 1964, inclusive, of which approximately $38,000,000 will be required during 1962. The major items of the 1962 construction expenditures include: $1,703,238 for completion of the 220 mw Unit #1 and $10,188,416 for continuing installation of the 220 mw Unit #2 at Applicant's Sabine Station; $5,075,627 for the 220 mw Unit #2 at the Willow Glen Station; $10,105,497 for transmission lines, substations and other transmission facilities; $9,544,421 for distribution lines, substations and other distribution facilities; $579,000 for electric general plant; $554,000 for steam heating facilities; and, $650,000 for gas distribution facilities.

Written notice of the application has been given to the Texas Railroad Commission and the Louisiana Public Service Commission, and to the Governor of each of those States. Notice has also been given by publication in the Federal Register on April 7, 1962 (27 FR 3360), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before April 23, 1962, with the Federal Power Commission, Washington 25, D.C. No protest, petition or request to be heard in opposition to the granting of the application has been received.

The Commission finds:

(1) Applicant, a corporation, is a public utility within the meaning of Section 204 of the Federal Power Act, subject to the jurisdiction of the Commission as heretofore described and set forth in the Commission's order issued November 27, 1957, *Gulf States Utilities Company*, Docket No. E–6785 (18 FPC 701).

(2) The proposed issuance and sale of Bonds, as described above, will constitute an issuance of securities within the purview of Section 204 of the Federal Power Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204 (f) of the Act, and the proposed issuance of securities is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The proposed issuance and sale of Bonds, upon the terms and conditions and for the purposes specified in the application, as described above, are authorized, subject to the provisions of this order.

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2 (k) (3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2 (k) (4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

(C) This authorization shall expire unless the transaction hereby authorized is consummated within 90 days from the date of issuance of this order.

(D) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(E) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States with respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

INTERSTATE POWER COMPANY, DOCKET NO. E-7028

ORDER AUTHORIZING THE ISSUANCE OF PROMISSORY NOTES

(Issued May 4, 1962)

Interstate Power Company (Applicant), incorporated under the laws of the State of Delaware and doing business in the States of Illinois, Iowa, Minnesota and South Dakota, with its principal business office at 1000 Main Street, Dubuque, Iowa, filed an application on March 23, 1962, as supplemented April 30, 1962, for authority, pursuant to Section 204 of the Federal Power Act, to issue unsecured Promissory Notes in the aggregate principal amount of $7,000,000, outstanding at any one time.

Applicant proposes to issue $1,350,000, principal amount, of the proposed Notes, to evidence bank loans to be secured under a credit agreement, dated March 14, 1962, with the following commercial banks located in Iowa and Minnesota:

Name of lending bank	Principal amount to be loaned
The First National Bank of Alberta Lea, Alberta Lea, Minnesota	$40,000
Freeborn National Bank of Albert Lea, Albert Lea, Minnesota	40,000
The City National Bank of Clinton, Clinton, Iowa	120,000
Clinton National Bank, Clinton, Iowa	40,000
American Trust & Savings Bank, Dubuque, Iowa	400,000
The First National Bank, Dubuque, Iowa	160,000
Dubuque Bank & Trust Company, Dubuque, Iowa	200,000
The First National Bank of Mason City, Mason City, Iowa	175,000
United Home Bank & Trust Company, Mason City, Iowa	175,000
Total	1,350,000

Each of the proposed Notes evidencing loans from the above-named Iowa and Minnesota banks will be dated as of June 15, 1962; will mature on May 31, 1963; and, will bear interest at the prime commercial rate of The Chase Manhattan Bank, of New York City, for unsecured borrowing prevailing three business days prior to the date of issuance.

Applicant proposes to issue additional Notes not exceeding $5,650,000 in principal amount to evidence loans from The Chase Manhattan Bank and the Manufacturers Hanover Trust Company, both of New York City, under a credit agreement dated March 16, 1962. Under the terms of that agreement, each of the afore-mentioned New York banks will make loans to Applicant in an amount not exceeding $2,825,000. The loans are to be evidenced by Notes to be issued from time to time prior to December 31, 1962. Each Note will mature 360 days from the date of the first borrowing under the agreement or on May 31, 1963, whichever date shall be earlier, and will bear interest at the prime commercial rate of The Chase Manhattan Bank, of New York City, for unsecured borrowing prevailing three business days prior to the date of issuance.

The application states that no underwriter's or finder's fee will be paid in connection with proposed issuance of Notes, and that none of the proposed Notes will be resold to the general public.

Applicant states that it will use the proceeds from the issuance of the proposed Notes to finance, in part, its 1962 construction program, estimated to cost $10,611,300. Principal items of expenditure are, as follows: $1,800,000 for con-

struction of the 75,000 kw Unit #3 (total cost estimated at $10,052,000) at Applicant's Sherburn steam-electric generating plant, Fox Lake, Minnesota; $2,928,100 for major electrical distribution system additions; and, $925,800 for extensions to and replacements in Applicant's gas facilities. Included in Applicant's 1962 gas program are: the construction of 1.5 miles of 8-inch pipeline, at a cost estimated at $150,000, to provide an additional crossing of the Rock River, in Illinois, for its Hooppole-Clinton line; and the construction of 5.5 miles of 6-inch pipeline, at a cost estimated at $240,000, to extend natural gas service to the Town of Camache, Iowa. Applicant states that it intends to file, in the near future, applications for certificates of convenience and necessity for the afore-mentioned gas facility construction; and the present application is subject to the condition that none of the proposed Notes will be issued to obtain funds for the payment of the cost of construction of those facilities prior to the issuance by this Commission of such certificates in accordance with the Natural Gas Act.

Written notice of the application has been given to the Illinois Commerce Commission, the Iowa State Commerce Commission, the Minnesota Railroad & Warehouse Commission, and the South Dakota Public Utilities Commission, and to the Governor of each of those States. Notice of the application was also published in the Federal Register on April 4, 1962 (27 F.R. 3216), stating that any person desiring to be heard or to make any protest with reference to the application should, on or before April 17, 1962, file a petition or protest with the Federal Power Commission, Washington 25, D.C. No protest or petition or request to be heard in opposition to the granting of the application has been received.

The Commission finds:

(1) Applicant, a corporation, is a public utility within the meaning of Section 204 of the Federal Power Act, subject to the jurisdiction of the Commission as heretofore described and set forth in the Commission's order issued May 2, 1961, *Interstate Power Company*, Docket No. E-6985 (25 FPC 889).

(2) The proposed issuance of Promissory Notes, as described above, will constitute an issuance of securities within the preview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State Commission within the meaning of Section 204(f) of the Act; and the proposed issuance of Promissory Notes, as described above, is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance of Promissory Notes in the aggregate principal amount of $7,000,000, all as described above, will be in excess of 5% of the par value of the other securities of Applicant, and, therefore, will not be exempt by virtue of Section 204(e) of the Act from the requirements of Section 204(a) of the Act.

(5) The proposed issuance of Promissory Notes, described above, will be exempt from the competitive bidding requirements of Section 34.1a of the Commission's Regulations under the Federal Power Act by reason of paragraph 34.1a (a) (2) thereof.

(6) The proposed issuance of Promissory Notes, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility, and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

(7) The period of public notice given in this matter is reasonable.

The Commission orders:

(A) The proposed issuance of Promissory Notes by the Applicant, in an aggregate principal amount of not to exceed $7,000,000, at any one time outstanding, upon the terms and conditions and for the purposes set forth in the application, is hereby authorized, subject to the provisions of this order.

(B) This authorization is expressly conditioned upon the final maturity of all Notes to be issued pursuant thereto, being not later than May 31, 1963, and that none of the notes will be issued to obtain funds for the payment of the cost of construction of the gas facilities described in the application prior to the issuance by this Commission of certificates of public convenience and necessity in accordance with the Natural Gas Act.

(C) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuations, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(D) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States in respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

IOWA SOUTHERN UTILITIES COMPANY, DOCKET NO. CP61-269

FINDINGS AND ORDER DIRECTING ESTABLISHMENT OF PHYSICAL CONNECTION OF TRANSPORTATION FACILITIES AND DELIVERY OF NATURAL GAS

(Issued May 4, 1962)

Iowa Southern Utilities Company (Applicant) a Delaware corporation with its principal place of business in the City of Centerville, Iowa, filed an application on April 13, 1961, for an order pursuant to section 7(a) of the Natural Gas Act, directing Michigan Wisconsin Pipe Line Company (Michigan Wisconsin) to install a gas measuring station and related facilities to provide city gate delivery of natural gas to Applicant for delivery in Danville, Iowa.

Applicant proposes to construct and operate a natural gas distribution system in Danville, Iowa. The third year estimated cost will be $69,355. Applicant indicates that it will be unnecessary to construct lateral facilities to connect with Michigan Wisconsin.

Applicant proposes to finance the cost of construction of these facilities as part of its construction budget which will be financed by interim bank loans and internally generated funds. The permanent types of financing has not yet been determined.

Applicant estimated the requirements of Danville, Iowa, as follows:

Year	Volumes in Mcf	
	Peak day	Annual
1	133	15,132
2	215	23,841
3	252	28,471

Applicant indicates that the proposed gas supply would be provided by the present maximum daily quantity and annual contract quantity available from Michigan Wisconsin.

Applicant states that it has already received a franchise for service in Danville, Iowa.

Notice of the aforesaid application was issued on November 7, 1961 and published in the Federal Register (26 F.R. 10707). Michigan Wisconsin filed a response to said application on May 29, 1961, stating that it was willing to provide the natural gas service requested, provided Applicant constructs and operates the necessary regulating equipment and the lateral extending from Danville to Michigan Wisconsin's existing pipeline facilities. Applicant indicated in its application that the ¼ mile lateral which would be necessary to attach to Michigan Wisconsin would be used as a distribution line to serve customers along its route.

No other protests, petitions to intervene or notices of intervention were filed.

The Commission finds:

(1) Michigan Wisconsin Pipe Line Company is a "natural-gas company" within the meaning of the Natural Gas Act.

(2) Applicant, Iowa Southern Utilities Company, a Delaware corporation having its principal place of business in the city of Centerville, Iowa, is duly authorized to sell and distribute natural gas in the State of Iowa.

(3) It is necessary and desirable in the public interest to direct Michigan Wisconsin to establish physical connection of its transmission system with the facilities which Applicant proposes to construct and operate and to sell and deliver, within Iowa Southern's authorized contract demand, natural gas for resale in Danville, Iowa, as hereinbefore described and as more fully described in the application in this proceeding.

(4) The requirement that Michigan Wisconsin serve Applicant, as proposed herein, will not place an undue burden upon Michigan Wisconsin nor impair its ability to render adequate service to its existing customers.

(5) The directive hereinafter issued should be conditioned upon Applicant's commencing taking of natural gas thereunder within one year from the date of issuance of this order.

The Commission orders:

(A) Michigan Wisconsin Pipe Line Company be and it is hereby directed to establish physical connection of its transmission system with the facilities which Iowa Southern Utilities Company proposes to construct and operate, and to sell and deliver, as part of Iowa Southern Utilities Company's authorized contract demand, volumes of natural gas, under Michigan Wisconsin's appropriate gas rate schedules on file with the Commission, for resale in Danville, Iowa, as hereinbefore described and as more fully described in the application in this proceeding, providing Iowa Southern Utilities Company commences the purchase of such natural gas within one year from the date of issuance of this order.

(B) Michigan Wisconsin Pipe Line Company shall report to the Commission in writing and under oath the date of commencement of service to Applicant hereunder within ten days of the commencement thereof.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

MICHIGAN GAS STORAGE COMPANY, DOCKET NO. CP62-164

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 4, 1962)

On January 11, 1962, Michigan Gas Storage Company (Applicant) filed in Docket No. CP62-164 an application pursuant to Section 7(c) of the Natural

Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of certain facilities, and the sale and delivery of natural gas to Consumers Power Company (Consumers) for resale and distribution in the City of Coleman, Midland County, Michigan, all as more fully set forth in the application.

Applicant proposes to establish a new delivery point to Consumers and to construct and operate the necessary metering and regulating facilities at that point. At the present time no natural gas service is being rendered in the City of Coleman. The proposed service will be provided with gas presently available to Consumers from Applicant, and no additional supplies will be required. The new delivery point will be located on Applicant's 12-inch Missaukee Line extending from its Muskegon River Compressor Station in Clare County, Michigan, southeasterly to its M–20–30 junction in Midland County, Michigan.

Consumers estimates the market requirements for the City of Coleman for the first and third years of service to be as follows:

	First year	Third year
	Mcf	*Mcf*
Peak day	482	501
Annual	66,090	76,622

The proposed facilities will cost $19,000, and will be financed from funds on hand.

Pursuant to due notice, a public hearing was held in Washington, D.C., on April 24, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Michigan Gas Storage Company, a Michigan corporation having its principal place of business in Jackson, Michigan, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of December 3, 1946, in Docket No. G–731 (5 FPC 965).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof and the proposed sale and delivery of natural gas by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The proposed construction and operation of facilities and the proposed sale of natural gas to Consumers Power Company for resale are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act

and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Michigan Gas Storage Company, to construct and operate the facilities and to sell and deliver natural gas to Consumers Power Company for resale, all as hereinbefore described and as more fully described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The time within which the facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act is hereby fixed at six months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

SOUTHERN CALIFORNIA EDISON COMPANY, DOCKET NO. CP61-172; TENNESSEE CALIFORNIA GAS TRANSMISSION COMPANY, DOCKET NO. CP61-173; CALIFORNIA GAS TRANSMISSION COMPANY, DOCKET NO. CP61-174; TENNESSEE CALIFORNIA GAS TRANSMISSION COMPANY, DOCKET NO. CP61-212

ORDER DEFERRING RULING ON MOTION FOR APPLICANTS TO SHOW CAUSE WHY THEIR APPLICATIONS ARE NOT LEGALLY INSUFFICIENT UNLESS TEXAS PRODUCERS FILE CERTIFICATE APPLICATIONS

(Issued May 4, 1962)

On March 30, 1962, Southern California Gas Company, Southern Counties Gas Company of California, and Pacific Lighting Gas Supply Company Movants), interveners in the above-entitled proceedings filed a motion for applicants to show cause why their applications are not legally insufficient unless Texas producers file certificate applications. The California Public Utilities Commission orally joined in the motion during the presentation of its opening statement in the hearing in these proceedings.

The Movants allege that natural gas purchased in Texas is to be mingled with gas purchased in the Republic of Mexico and that a portion of this total gas stream, after entry into California, will be resold by the purchaser, Southern California Edison Company (Edison).* This being so, they argue, then Section

*Edison proposes to purchase gas in Texas Railroad Commission District Number Four from the Humble Oil & Refining Company, Pan American Petroleum Corporation, Sun Oil Company and the Shell Oil Company.

1(b) of the Natural Gas Act (Act) requires the Texas producers to obtain certification of their sales to Edison pursuant to Section 7(c) of the Act. Noting that Edison's contracts with the Texas producers prohibit the resale of Texas produced gas, the Movants rely on our decision in *Lo-Vaca Gathering Company*, 26 FPC 606, Opinion No. 348 and order issued October 23, 1961; petition for review filed in *Lo-Vaca Gathering Company* v. *FPC*, No. 19478 (CA5), for the proposition that a sale of gas in interstate commerce for resale cannot be transmuted into something else by contract.

Answers to the motions were filed by Edison and jointly by Tennessee California Gas Transmission Company (Tenncal) and California Gas Transmission Company (CalGas). The answers, in substance, contend that while it is true that Edison proposes to make natural gas available for peaking service to local distributing utilities in California, contracts for such a service have not been executed, and therefore, Movants have failed to show that a jurisdictional sale of natural gas for resale will be consummated.

The factual circumstances surrounding Edison's proposal are, at this juncture of the record, too ambiguous for us to discern the precise nature of the peaking service. For example, it is unclear as to whom the actual and potential users of the service will be and the form of service agreement Edison is willing to execute. Nor does the record contain *pro forma* copies of rate schedules or tariffs setting forth the terms and conditions and particularly the availability of the service. Insofar as we are able to ascertain the content of Edison's proposal, it is apparent that if any portion of the total gas stream, consisting of gas produced in both Texas and Mexico, is to be resold by Edison or CalGas to other companies, then the producers of the Texas produced gas would be required to file for certificates of public convenience and necessity pursuant to the provisions of the Natural Gas Act.

As a consequence of the presently undeveloped state of the record on Edison's peaking service proposal, decision on the motion should be deferred at this time and the motion should be referred to the presiding examiner to be ruled upon as a part of his recommended initial decision.

The Commission finds:

The Commission deems it appropriate and advisable in the public interest that the motion for issuance of an order directing the present applicants to show cause why their applications are not legally insufficient, filed on March 30, 1962 and orally joined by the California Public Utilities Commission on April 10, 1962, be referred to the presiding examiner to be ruled upon in connection with, and as a part of his initial decision after the conclusion of the hearing in this proceeding.

The Commission orders:

The motion for issuance of an order directing the present applicants to show cause why their applications are not legally insufficient, filed on March 30, 1962 and orally joined by the California Public Utilities Commission on April 10, 1962 is referred to the presiding examiner to be ruled upon, in connection with, and as a part of his initial decision after the conclusion of the hearing in this proceeding.

Commissioner O'Connor *not participating.*

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. CP62-112

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 4, 1962)

On November 1, 1961, as supplemented on December 15, 1961, Transcontinental Gas Pipe Line Corporation (Applicant) filed in Docket No. CP62-112 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of an 8-inch tap and appurtenant equipment to serve an emergency connection between Applicant's 36-inch main transmission line and the 16-inch main transmission line of North Carolina Natural Gas Corporation (North Carolina Natural) near the Cowan's Ford Project of the Duke Power Company in Iredell County, North Carolina, all as more fully set forth in the application, as supplemented.

The proposed emergency connection between the two systems will be used as an alternative delivery point to provide natural gas service to North Carolina Natural, an existing customer, for resale, in the event that North Carolina Natural's main 16-inch pipeline should be damaged subsequent to its flooding by the Cowan's Ford Project. North Carolina Natural has requested the proposed connection to avoid possible interruption or impairment of service to its customers.

The proposed facilities are estimated to cost approximately $12,300 and will be initially financed by Applicant from company funds. North Carolina Natural has agreed to reimburse Applicant for the entire cost of the facilities.

Pursuant to due notice, a public hearing was held in Washington, D.C., on April 26, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Transcontinental Gas Pipe Line Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 28, 1950, in Docket No. G-1277 (9 FPC 32).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities and the transportation of natural gas as proposed by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Transcontinental Gas Pipe Line Corporation, to construct and operate an emergency interconnection with the facilities of North Carolina Natural Gas Corporation and to transport natural gas as hereinbefore described, all as more fully described in the application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations.

(C) The time within which the subject facilities shall be completed and placed in regular operation, as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act, is hereby fixed at three months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

CITIES SERVICE GAS COMPANY, DOCKET NO. CP62-147

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 7, 1962)

On December 14, 1961, Cities Service Gas Company (Applicant) filed in Docket No. CP62-147 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the sale and delivery of natural gas on a firm basis to Tri-City Gas Company (Tri-City) for resale in and about the Towns of Edna and Bartlett, Kansas.

Applicant states that it has sold and delivered natural gas to Tri-City for resale in Edna and Bartlett as well as for resale in Chetopa, Kansas, under its emergency service FPC Gas Rate Schedule E. However, Applicant states further that Tri-City has advised that its present local source of gas for Edna and Bartlett is diminishing and that it must obtain at least 60 percent of its requirements for those communities from Applicant on a firm basis. Service for Chetopa will continue under Rate Schedule E.

The estimated peak day and annual natural gas requirements for Edna and Bartlett in the third year of service are:

	Mcf at 14.73 psia	
	Third year	Applicant's portion at 60% service
Peak day	450	270
Annual	56,371	33,822

The proposed sale and delivery of natural gas will be made by Applicant pursuant to its FPC Gas Rate Schedules F–2, C–2 and I–2.

No additional facilities will be required to render the proposed service.

Pursuant to due notice, a public hearing was held in Washington, D.C., on April 24, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Cities Service Gas Company, a Delaware corporation having its principal place of business in Oklahoma City, Oklahoma, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of December 28, 1943, in Docket No. G–298 (4 FPC 471).

(2) The sale and delivery for resale of natural gas at the proposed delivery point hereinbefore described, as more fully described in the application in this proceeding, are to be made in interstate commerce subject to the jurisdiction of the Commission, and such proposed sale and delivery by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The proposed sale and delivery for resale of natural gas at the proposed delivery point by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (c) (3) and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Cities Service Gas Company, to sell and deliver for resale natural gas to Tri-City, at the proposed delivery point, as hereinbefore

described, all as more fully described in the application, herein, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (c) (3) and (e) of Section 157.20 of such Regulations.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NORTHERN NATURAL GAS COMPANY, DOCKET NOS. G–19040, RP61–23, AND RP62–6; NORTHERN NATURAL GAS COMPANY (FORMERLY PERMIAN BASIN PIPELINE COMPANY), DOCKET NO. G–19041

ORDER APPROVING RATE SETTLEMENT AGREEMENT AND TERMINATING PROCEEDINGS

(Issued May 7, 1962)

On December 21, 1961, the Commission issued an order approving a rate settlement agreement in Docket Nos. G–19040 and G–19041, prescribing refunds, and terminating the proceedings in Docket Nos. G–19040, G–19041 and RP61–23, 26 FPC 901, excepting for the issue of rate design in said dockets as it applies to the relative levels of the commodity charges and demand charges of the rates provided for in the settlement agreement. On February 2, 1962, the Commission issued an order consolidating the proceedings in Docket No. RP62–6 with the other proceedings involved herein.

Pursuant to the notice of the Secretary of the Commission, issued on February 23, 1962, the hearing in these proceedings was reconvened on March 27, 1962, at which time the presiding examiner granted a request for continuance for the purpose of permitting the parties to confer regarding a proposed stipulation of settlement. Subsequent to such conferences, on April 12, 1962, there was incorporated in the record of the proceeding a statement of a proposed settlement (Tr. 1887 to 1893) which is attached hereto as Appendix I. All parties present concurred in the proposed settlement, or voiced no opposition thereto. The Coal Interveners [1] reserved making a statement of position at that time.

On April 13, 1962, said Coal Interveners advised the presiding examiner by letter that they "will interpose no objection to the proposed stipulation agreement as set forth at transcript pages 1887–1893, incl." Consequently, all parties to these proceedings have either affirmatively concurred in the proposed settlement agreement, or have stated that they have no objection thereto.

The proposed settlement agreement provides that Northern will file revised tariff sheets with the Commission, on or before November 27, 1962, to be effective December 27, 1962, containing rates which will result in increasing the present commodity rates in all rate schedules in Zones 1, 2, and 3 and rate schedules PL-b and PO-B by 1¢ per Mcf, with a compensating reduction in the demand charges under such rate schedules. The present rates in all other rate schedules in Zones B and C would remain unchanged.

The Commission finds:

(1) The settlement of the rate design issue in the proceedings in Docket Nos. G–19040, G–19041, RP61–23 and RP62–6, on the basis of the settlement agree-

[1] Fuels Research Council, Inc., National Coal Association, United Mine Workers of America, Mid-West Coal Producers Institute, Inc., Upper Lake Docks Coal Bureau, Inc., and The Chesapeake and Ohio Railway Company.

ment attached hereto as Appendix I is reasonable, proper and in the public interest in carrying out the provisions of the Natural Gas Act and should be approved and made effective subject to the terms and conditions hereinafter ordered.

(2) Good cause exists for terminating the proceedings in Docket Nos. G–19040, G–19041, RP61–23 and RP62–6 subject to the terms and conditions hereinafter ordered.

The Commission orders:

(A) The settlement of each of the rate design issues in these proceedings as proposed in the settlement statement discussed above, and appended hereto, subject to the terms and conditions hereinafter specified, is approved and made effective.

(B) Northern shall file tariff sheets, acceptable to the Commission, which shall effectuate the rates and charges shown in Section 1 of the settlement agreement, appended hereto, on or before November 27, 1962, to be effective December 27, 1962.

(C) Except as modified or superseded, the Settlement Agreement approved by the order issued December 21, 1961, aforementioned, and the terms and conditions set forth in said order, remain in full force and effect.

(D) Subject to the conditions contained in the order issued December 21, 1961, and in this order, the proceedings in Docket Nos. G–19040, G–19041, RP61–23 and RP62–6 hereby are terminated.

(E) This order is without prejudice to any findings or orders which have heretofore been made or may hereafter be made by the Commission in any of the above-captioned proceedings, and is without prejudice to claims or contentions which may be made by the Commission, the Commission staff, Northern, or any other party hereto in any other proceedings now pending or hereafter instituted by or against Northern or any other companies, persons or parties affected by this order.

STATEMENT OF PROPOSED SETTLEMENT

By order issued December 21, 1961 in the above-captioned matters (except Docket No. RP62–6), the Commission approved a rate settlement disposing of all issues in the above-captioned matters except the issue of rate design in Docket Nos. G–19040, G–19041 and RP61–23. Specifically this issue applies to the relative levels of the commodity charges and demand charges of the rates provided for in the settlement agreement, and which are required to produce the annual revenues to Northern on the basis of said settlement agreement.

Pursuant to such settlement agreement Northern filed with the Commission revised tariff sheets, to be effective December 27, 1961, containing the following rates:

Rate schedule (zone)	Demand charge	Commodity charge
		Cents
CD–1 (Zone 1)	$3.314	21.9
R–1 (Zone 1)	None	21.9
CD–2 (Zone 2)	3.624	22.4
R–2 (Zone 2)	None	22.4
CD–3 (Zone 3)	3.944	22.9
R–3 (Zone 3)	None	22.9
PL–3 (Zone 3)	3.994	22.9
PO–3 (Zone 3)	None	22.9
CD–B (Zone B)	3.714	25.97
R–B (Zone B)	None	25.97
CD–C (Zone C)	4.034	26.47
R–C (Zone C)	None	26.47

Such rates were accepted by the Commission by letter dated January 19, 1962 and, under the provisions of the aforesaid settlement agreement, are to remain in effect until December 27, 1962 or until six months after the date of any Commission order in respect to adjustments in such demand and commodity charges, whichever date is later.

By order issued February 2, 1962 in Docket No. RP62–6 the Commission suspended rate schedules PL–B and PO–B which had been tendered by Northern on January 4, 1962 covering the sale of up to 75,000 Mcf per day to Michigan-Wisconsin Pipe Line Company (Michigan-Wisconsin) in Northern's Rate Zone B as authorized in Docket No. G–20571 by order and Opinion No. 345 issued June 28, 1961. On or about February 19, 1962 Northern filed a motion to effectuate such rates, and, pursuant to the provisions of said order issued February 2, 1962, such rates became effective on February 28, 1962. By further provisions of said order of February 2, 1962 the proceedings in Docket No. RP62–6 were consolidated for the purposes of hearing and decision with the proceedings in Docket Nos. G–19040, *et al.*

By order issued February 23, 1962 the Commission reconvened the hearing in the above-captioned matters on March 27, 1962 and thereafter, upon motion of Staff Counsel, concurred in by all parties, the hearing was recessed from time to time to permit the parties to confer in an effort to compromise and settle the sole remaining issue of rate design in such dockets.

For the purpose of settling all remaining issues involved in the above-captioned proceedings the parties agree that the following proposal be submitted to the Commission, to-wit:

SECTION I

Future Rates

Northern will, after issuance of a Commission order approving this proposed settlement, file revised tariff sheets with the Commission on or before November 27, 1962, to be effective December 27, 1962, containing the following rates:

Rate schedule (zone)	Demand charge	Commodity charge
		Cents
CD-1 (Zone 1)	$3.062	22.9
R-1 (Zone 1)	None	22.9
CD-2 (Zone 2)	3.372	23.4
R-2 (Zone 2)	None	23.4
CD-3 (Zone 3)	3.692	23.9
R-3 (Zone 3)	None	23.9
PL-3 (Zone 3)	3.692	23.9
PO-3 (Zone 3)	None	23.9
CD-B (Zone B)	3.714	25.97
R-B (Zone B)	None	25.97
PL-B (Zone B)	4.009	24.4
PO-B (Zone B)	None	24.4
CD-C (Zone C)	4.034	26.47
R-C (Zone C)	None	26.47

The above filings will result in increasing the present commodity rates in all rate schedules in Zones 1, 2 and 3 and rate schedules PL–B and PO–B by 1¢ per Mcf, with a compensating reduction in the demand charges under such rate schedules, and leaving unchanged the present rates in all other rate schedules in Zones B and C.

SECTION II

Other Conditions and Provisions

If as a result of the increases in the commodity charges of the rate schedules set out in Section I above, Northern loses any jurisdictional or nonjurisdictional interruptible sales during 1963 as compared with such sales as made in 1960, then Northern may file on or before October 27, 1963, to be effective December 27, 1963, the necessary increases in the demand charges in such rate schedules in an amount equivalent to the difference between the annual revenues lost based upon the rates in Section I above, and the annual variable costs during 1960 attributable to such sales lost during 1963 as a result of filing such increased commodity rates and any suspension thereof will be shortened so that Northern will be permitted to collect such increased demand charges, subject to refund, from and after December 27, 1963; provided, however, that the only portion subject to refund shall be those revenues attributable to such increases in demand charges; provided further, that the supporting data to be filed with such increases and the proof to be offered at any hearing thereon, shall be limited to that data necessary to support the claim of the loss of such sales as a result of the increases in commodity charges set out in Section I above, the volumes of sales lost, and the revenues and the variable costs associated therewith; and, provided further, however, that if Northern, prior to December 27, 1963, commences collecting increased rates under the rate schedules here involved as a result of filing increased rates based on increased costs of service, then the provisions of this Section II shall be of no further force and effect.

SECTION III

Miscellaneous Provisions and Conditions

A. *Acceptance by the Commission.* The agreement reached by the parties and set forth in this Statement of Proposed Settlement is expressly conditioned on the Commission's acceptance of all of the terms of this proposed settlement.

B. *Waiver.* With respect to the rate schedules to be filed pursuant to Section I hereof, and proposed to be made effective December 27, 1962, it is requested that the Commission, by special provision in its order approving this settlement, waive compliance by Northern with the requirements of the Commission's regulations under the Natural Gas Act, particularly Part 154 thereof (18 CFR, Part 154), to the extent, if any, necessary to carry out the provisions of this agreement as provided in said Sections I and II.

C. *Reservations.* By making this agreement, neither the Commission Staff, Northern, any other party hereto, nor any affected person is to be considered as agreeing with any cost of service determinations or allocations, or with any principles underlying or supposed to underlie cost of service determinations or allocations or rate design used in arriving at the rates and charges to be applicable in the future as agreed upon herein, and neither the Commission Staff, Northern, any other party hereto, nor any affected person is to be prejudiced or bound thereby in any future proceeding or proceedings.

Except as provided in Section IV, Paragraph D, of the Settlement Agreement approved by the Commission in its order of December 21, 1961, nothing contained herein shall be construed as limiting Northern's right to file new or amended rate schedules at any time, nor is it to be considered that by making this agreement Northern, any other party, or any affected person has waived any legal right or right of action which it might have with respect to matters other than those herein specifically agreed upon, including, but not limited to, the right here-

after to contest the differentials in commodity rates between zones or the propriety of more than one level of commodity rate in any given zone.

Except as modified or superseded herein, the Settlement Agreement approved by the Commission order issued December 21, 1961 in Docket Nos. G–19040, *et al.*, remains in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

CITY OF PASADENA, CALIFORNIA, PROJECT NO. 1250

ORDER GRANTING EXEMPTION FROM PAYMENT OF ANNUAL CHARGES

(Issued May 8, 1962)

Application was filed on March 26, 1962, by the City of Pasadena, California, licensee for Project No. 1250, for exemption from payment of the net amount of annual charges under the license for the project for the calendar year ended December 31, 1961, pursuant to the provisions of Section 10(e) of the Federal Power Act (Act) and regulations of the Commission thereunder, on the ground that the balance of project power not used for municipal purposes was sold to the public without profit.

The annual charges under the license for the project for the year involved amounted to $157.42. However, in accordance with the Commission's regulations, the statement of annual charges rendered by the Commission for the project for the year involved, billed the licenseee for $142.18, or 90.32 percent of the total charges assessable, representing the ratio of the power sold by the licensee during the year 1961 to the total power generated.

The application shows that the project operations for the year 1961 resulted in a net loss of $27,919.41, and that the balance of the power was sold by the licensee only to ultimate consumers without profit.

The Commission finds:

(1) The licensee is a municipality within the meaning of Section 3(7) of the Act, and is entitled to claim exemption from payment of annual charges under Section 10(e) of the Act.

(2) The licensee is entitled to exemption of the net amount of annual charges for which it was billed for the year 1961.

The Commission orders:

The licensee is hereby exempted from liability under the license for Project No. 1250 for payment of the net amount of annual charges for which it was billed for the calendar year 1961.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

UNITED STATES DEPARTMENT OF THE INTERIOR, BONNEVILLE POWER ADMINISTRATION, DOCKET NO. E–7023

ORDER CONFIRMING AND APPROVING EXCEPTION TO GENERAL RATE SCHEDULE PROVISIONS

(Issued May 8, 1962)

By order issued December 16, 1959, *Bonneville Power Administration*, Docket No. E–6887 (22 FPC 1046), the Federal Power Commission confirmed and approved Bonneville Power Administration's Wholesale Power Rate Schedules

and the General Rate Schedule Provisions applicable thereto for a five-year period beginning December 20, 1959, and ending December 19, 1964.

On February 7, 1962, the Secretary of the Interior, on behalf of the Bonneville Power Administration (Bonneville), filed with the Commission for confirmation and approval, pursuant to the provisions of the Bonneville Act (50 Stat. 731), an exception to Bonneville's General Rate Schedule Provisions applicable to the Pacific Northwest Coordination Agreement (1961–1962) and similar coordination agreements which Bonneville may execute for the period ending August 31, 1962.

Section 6(k) of the aforesaid Coordination Agreement reads as follows:

> The Adjusted Load actually served by a System (exclusive of secondary loads which can be served within the limitations of the foregoing provisions of this section) shall not exceed that System's Firm Load Carrying Capability during the Drawdown Period. A System may modify its Firm Load Carrying Capability at any time during the seven-month period starting September 1 so long as the accumulation of such modified average monthly energy capabilities does not exceed the accumulation of the monthly totals tabulated in Exhibit 2 by more than seven minus N (7—N) percent in which N is the number of whole months since 12:01 a.m., September 1. * * *

Exhibit 2, which is referred to above in Section 6(k), is a table which sets forth certain monthly firm load carrying capabilities for the one-year period ending August 31, 1962, for each party to the Coordination Agreement.

The above-stated Section 6(k) differs from Subsection B(2), Section 2.3 of Bonneville's General Rate Schedule Provisions in that it provides for modification of a System's Firm Load Carrying Capability in an "after-the-fact" manner. Subsection B(2) requires that determinations of assured monthly capabilities be made prior to the beginning of each operating year.

The Secretary of the Interior states that the purpose of the provision in the Coordination Agreement is the realization of optimum power production from existing facilities by allowing flexibility in the operation of each System's resources, and that similar provisions are expected to be offered to all purchasers similarly situated for the period ending August 31, 1962.

Information supplied by Bonneville shows that application of the provisions of Section 6(k) instead of Subsection B(2), Section 2.3 of the General Rate Schedule Provisions would result in a maximum reduction of approximately $90,000 in Bonneville's revenues for the year ending August 31, 1962. However, that information also indicates that the Coordination Agreement will result in a net increase in revenues for that period of between $400,000 and $500,000. The flexibility of operations permitted by Section 6(k) is essential to the attainment of the objectives of the Coordination Agreement.

Notice of the proposed exception to Bonneville's currently effective General Rate Schedule Provisions was published in the Federal Register on March 17, 1962 (27 F.R. 2576), stating that any person desiring to make comments or suggestions with respect thereto should submit the same on or before March 30, 1962. No comments or suggestions have been received.

The Commission finds:

It is appropriate for the purposes of the Bonneville Act that the proposed exception to Bonneville's General Rate Schedule Provisions contained in Section 6(k) of the Pacific Northwest Coordination Agreement and in similar coordination agreements to be executed by Bonneville for the period ending August 31, 1962, be confirmed and approved for the period ending August 31, 1962.

The Commission orders:

(A) The proposed exception to Bonneville's General Rate Schedule Provisions contained in Section 6(k) of the Pacific Northwest Coordination Agreement and in similar coordination agreements to be executed by Bonneville for the period ending August 31, 1962, hereby is confirmed and approved for the period ending August 31, 1962.

(B) The foregoing confirmation and approval of the exception to Bonneville's General Rate Schedule Provisions contained in Section 6(k) of the Pacific Northwest Coordination Agreement is without prejudice to any headwater benefit determination by this Commission pursuant to the provisions of Section 10(f) of the Federal Power Act.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

YADKIN, INC., PROJECT NO. 2197

ORDER FURTHER AMENDING LICENSE (MAJOR)

(Issued May 8, 1962)

Application was filed on December 14, 1961 by Yadkin, Inc., licensee for major Project No. 2197, for further amendment of its license for the project located on the Lower Yadkin stretch of the Yadkin-Pee Dee River in Stanly, Montgomery, Davidson and Rowan Counties, North Carolina.

The application seeks amendment of the license to exclude therefrom a 30,000 kva transformer bank located at the Narrows development, and a double circuit 110 kv transmission line between that development and the Badin substation, with the exception of about 1100 feet which will be utilized in connection with other project transmission facilities. The licensee proposes to dismantle the 110 kv transmission line and dismantle and retire the transformer bank. Filed as part of the application and for Commission approval were revised Exhibits J, K and M showing revisions in the project boundary and changes in equipment to reflect the exclusion of the transmission line and transformers.

The 110 kv line and transformers were formerly used to provide for the interchange of power between the licensee and Carolina Power and Light Company or the licensee and Duke Power Company. The licensee has been engaged in rebuilding its Badin substation, which is not a part of the project, and with the completion of the first phase of the rebuilding there is now a continuous three-way interconnection at that substation between the systems of the licensee, Carolina Power and Duke. Therefore, the 110 kv transmission line and the transformers are no longer necessary to provide the interchange connection. The aforesaid 30,000 kva transformer bank and the 110 kv Narrows-Badin transmission line, except for 1100 feet parallel to the High Rock-Badin 88 kv line, are not used or useful for project purposes.

There are four 13.2 kv lines, which are part of the project, extending between the Narrows development and the Badin substation. These four existing lines are used to transmit the entire output of the Narrows plant to the Badin substation.

The Commission finds:

(1) The license, further amended as hereinafter ordered, is in the public interest.

(2) The aforesaid transformer bank and the 110 kv Narrows-Badin transmission line, with the exception of the 1100 foot section, should be eliminated from the license for the project as hereinafter provided.

(3) The following described revised exhibits filed as part of the application conform to the Commission's rules and regulations and should be approved as part of the license for the project and the exhibits hereinafter described as being superseded should be eliminated from the license—all as hereinafter provided:

Exhibit J (Second Revision) (FPC No. 2197–77), superseding Exhibit J (FPC No. 2197–9) now part of the license;

Exhibit K, Sheets 3 and 4 (First Revisions) (FPC Nos. 2197–78 and –79) superseding Exhibit K (FPC Nos. 2197–15 and –16) now part of the license; and

Exhibit M, Page 7 filed in the Commission on December 14, 1961, superseding Exhibit M, Page 7 filed in the Commission February 6, 1956.

The Commission orders:

(A) The revised exhibits described in finding (3) above as conforming to the Commission's rules and regulations are approved as part of the license for Project No. 2197 and the exhibits described in the same finding as being superseded are eliminated from the license for the project.

(B) The license for Project No. 2197, as amended, is further amended, effective as of March 1, 1962, to eliminate from the project works of the Narrows development the 110-kv Narrows-Badin transmission line (described in subparagraph (b)(3) of the license as a two-circuit 100- and 110-kv transmission line extending to Badin substation), and the 30,000 kva transformer bank at the Narrows powerhouse.

(C) This amendment in the manner set out above shall not operate to alter or amend the license in any other respect, and shall not in any way constitute a waiver of any other part, provision or condition of the license as heretofore amended.

(D) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313(a) of the Federal Power Act and failure to file such an application shall constitute acceptance of this amendment of license. In acknowledgment of the acceptance of this amendment of license, it shall be signed for the licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Harold C. Woodward.

COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY, OHIO-MIDLAND LIGHT & POWER COMPANY, SOUTH CENTRAL RURAL ELECTRIC COOPERATIVE, INC., DOCKET NO. E–7036

ORDER AUTHORIZING SALE, ACQUISITION AND MERGER OR CONSOLIDATION OF FACILITIES

(Issued May 9, 1962)

Columbus and Southern Ohio Electric Company (Columbus) filed an application on April 26, 1962, as amended April 30, 1962, for an order, pursuant to Section 203 of the Federal Power Act, authorizing Columbus to acquire certain electric facilities from Ohio-Midland Light & Power Company (Midland) and to transfer and sell certain other electric facilities to Midland. On May 3, 1962, South Central Rural Electric Cooperative, Inc. (South Central) and Midland joined in the application, further requesting authorization for Midland to exchange the afore-mentioned electric facilities with Columbus,

for Midland to transfer to South Central those facilities acquired from Columbus together with its facilities remaining after the sale of certain other facilities to Columbus, and for South Central to acquire those facilities transferred to it by Midland. Columbus is a corporation organized under the laws of the State of Ohio and doing business in that State, with its principal business office at Columbus, Ohio. Midland, a corporation organized under the laws of the State of Ohio and doing business in that State, with its principal business office at Canal Winchester, Ohio, is a wholly-owned subsidiary of South Central and purchases all of its electric energy requirements from Columbus. Columbus and Midland supply electric energy to residential and commercial consumers in the same general locality in Franklin, Pickaway and Ross Counties, Ohio. South Central, a corporation organized under the laws of the State of Ohio and doing business in that State, with its principal place of business at Lancaster, Ohio, is a rural electric cooperative serving parts of Fairfield, Fayette, Franklin, Hocking, Licking, Madison, Muskingum, Perry, Pickaway and Ross Counties in south central Ohio. Neither Midland nor its parent South Central has any generation facilities.

Under the terms of a contract, dated October 9, 1961, between Columbus and Midland, Columbus proposes to transfer to Midland certain electric utility properties located west of Circleville, Ohio and in and adjacent to Ashville, Ohio in exchange for Midland's electric utility properties located in Groveport, Ohio and Obetz Junction, Ohio. In addition, Midland will sell to Columbus certain other electric utility facilities located in the City of Columbus, in the City of Circleville, in and adjacent to Hilliards and Reynoldsburg, and north of Chillicothe—all in the State of Ohio—and its railroad in Pickaway County, Ohio, including approximately two miles of trackage, rights-of-way, easements, locomotives, real estate and all other railroad properties. The agreement provides for the payment by Columbus to Midland of a base sum of $6,460,000, subject to certain adjustments between the date of the agreement and the closing date. The consideration as of March 31, 1962, would have been $6,063,000. Midland proposes to transfer the facilities obtained from Columbus together with its facilities remaining after the sale of certain facilities to Columbus to its parent South Central; Midland will then be dissolved.

Columbus proposes initially to reflect its proposed acquisition and disposition of properties by debits and credits to Account 102, Electric Plant Purchased or Sold, and, as this account is cleared, to charge the Electric Plant Acquisition Adjustment with respect to the transactions, subject to the approval of this Commission, directly to Account 216, Unappropriated Earned Surplus.

The tentative amounts shown on the books of Columbus as of March 31, 1962, would have been as follows:

	Acquired by Columbus from Ohio-Midland	Sold by Columbus to Ohio-Midland	Net amount
Estimated original cost of properties	$3,000,000	$145,000	$2,855,000
Estimated accumulated provision for depreciation on properties	400,000	37,000	363,000
Net amount	2,600,000	108,000	2,492,000
Consideration to be paid by Columbus			6,063,000
Acquisition adjustment on books of Columbus—acquisition adjustment to be charged to earned surplus			3,571,000

Columbus states in the application that it has reason to believe that its estimate of original cost of the property to be acquired may be conservatively low and the amount of the plant acquisition adjustment may be high, and that, for this reason the plant acquisition figure of $3,571,000 should be considered tentative and subject to change.

As stated in the application, Columbus has kept records of the original cost of its facilities by plant accounts, but the basis for such records has not been examined or approved by this Commission; depreciation with respect thereto has been kept only in the aggregate. Midland has not kept records of the original cost of its facilities, nor of the depreciation thereon, comparable to the records as prescribed in the Commission's Uniform System of Accounts. On the basis of a mixture of book amounts and of estimated original cost, it appears that Midland after the completion of the proposed transaction between Midland and Columbus will have a hybrid amount of plant of about $5,789,510 and a hybrid amount of applicable provision for depreciation of about $873,263 to transfer to the books of South Central. On this basis, pending the determination of the original cost in compliance with the Commission's Uniform System of Accounts, the computation is, as follows:

	Ohio-Midland per books as of December 31, 1961	Estimated original cost to be acquired from Columbus	Estimated original cost to be transferred to Columbus	Balance for transfer to South Central
Utility plant	$8,644,510	$145,000	($3,000,000)	$5,789,510
Accumulated provision for depreciation	1,236,263	37,000	(400,000)	873,263
Net plant	7,408,247	108,000	(2,600,000)	4,916,247

The application states that with respect to all of the areas to be acquired by Columbus, the lines of Columbus and Midland intersect and duplicate one another. Similarly, the lines of Midland and South-Central intersect and duplicate one another within the areas constituting a boundary between the two systems. The areas to be acquired by Columbus have generally had only one source of supply of electric energy. As Columbus incorporates these areas into its system, it will add additional sources of supply, thereby insuring more reliable service. Acquisition by South-Central of the facilities from Midland, will substantially strengthen South-Central's system and ultimately benefit its customers. The railroad operated by Midland will be taken over by Columbus, which is the only company making use of it at present in hauling coal to its Pickaway generating station. Applicants further state that the proposed consolidation of facilities of Columbus and South-Central will eliminate present uneconomical duplication of service and facilities.

As a result of the proposed transactions, those customers of Midland who will become customers of Columbus and who reside outside of the municipalities will experience some rate increase as a result of the application of rates recently approved by the Public Utilities Commission of Ohio. However, a substantial majority of the customers transferred to Columbus reside in municipalities, where the present rates will continue in effect. On the other hand, those customers of Midland who are transferred to South-Central will receive a rate decrease.

Written notice of the application has been given to the Public Utilities Commission of Ohio and to the Governor of that State. Notice of the application was also published in the Federal Register on April 28, 1962 (27 F.R. 4109),

stating that any person desiring to be heard or to make any protest with reference to said application should, on or before the 8th day of May, 1962, file with the Federal Power Commission, Washington 25, D.C., petitions or protests. No petition or protest or request to be heard in opposition to the granting of the application has been received.

The Public Utilities Commission of Ohio, by order entered March 15, 1962, approved the transactions proposed by Applicants herein, together with the abandonment by Midland of service as a public utility.

The Commission finds:

(1) Columbus, a corporation organized and existing under the laws of the State of Ohio, owns and operates facilities, among others, for the transmission and sale at wholesale of electric energy which is generated in Indiana and West Virginia and consumed in Ohio, all of which facilities are in addition to, and do not include facilities used for the generation of electric energy, facilities used in local distribution, or only for the transmission of electric energy in intrastate commerce, or facilities for the transmission of electric energy consumed wholly by the transmitter, and Columbus is, therefore, a public utility within the meaning of that term as used in Section 203 of the Federal Power Act.

(2) Midland, a corporation organized and existing under the laws of the State of Ohio, owns and operates facilities, among others, for the transmission of electric energy which is generated in Indiana and West Virginia and consumed in Ohio, all of which facilities are in addition to, and do not include facilities used for the generation of electric energy, facilities used in local distribution, or only for the transmission of electric energy in intrastate commerce, or facilities for the transmission of electric energy consumed wholly by the transmitter, and Midland is, therefore, a public utility within the meaning of that term as used in Section 203 of the Federal Power Act.

(3) South Central, a corporation organized and existing under the laws of the State of Ohio, owns and operates facilities, among others, for the transmission of electric energy which is generated in Indiana and West Virginia and consumed in Ohio, all of which facilities are in addition to, and do not include facilities used for the generation of electric energy, facilities used in local distribution, or only for the transmission of electric energy in intrastate commerce, or facilities for the transmission of electric energy consumed wholly by the transmitter, and South Central is, therefore, a public utility within the meaning of that term as used in Section 203 of the Federal Power Act.

(4) By the proposed transactions, as described above, Columbus will acquire and merge or consolidate with its facilities, subject to the jurisdiction of the Commission, electric facilities located in Groveport and Obetz Junction, in the City of Columbus, in the City of Circleville, in and adjacent to Hilliards and Reynoldsburg, and north of Chillicothe—all in the State of Ohio—which facilities are the property of Midland, another person, within the meaning and subject to the requirements of Section 203 of the Federal Power Act; and, Midland will acquire and merge or consolidate with its facilities, subject to the jurisdiction of the Commission, electric facilities located west of Circleville, Ohio, and in and around Ashville, Ohio, which facilities are the property of Columbus, another person, within the meaning and subject to the requirements of Section 203 of the Federal Power Act.

(5) By the proposed transactions, as described, above, Midland will, subsequent to the consummation of its transactions with Columbus, transfer all of its electric facilities to South-Central, another person, within the meaning and subject to the requirements of Section 203 of the Federal Power Act; and, South-

Central will acquire all of the electric facilities of Midland, another person, within the meaning and subject to the requirements of Section 203 of the Federal Power Act.

(6) The proposed acquisition of Columbus' electric facilities by Midland, and the proposed acquisitions of Midland's electric facilities by Columbus and by South-Central, as described above, upon the terms and conditions specified in the application and subject to the provisions of this order, will be consistent with the public interest, as expressed in Section 203 of the Act, for the reasons set forth in the recital above.

(7) The period of public notice given in this matter is reasonable.

The Commission orders:

(A) The proposed acquisition and merger or consolidation by Midland of certain electric facilities of Columbus; the proposed acquisition and merger or consolidation by Columbus of certain electric facilities of Midland; and the subsequent transfer to South-Central of all the electric facilities of Midland and the acquisition thereof and merger or consolidation thereof by South-Central, all as described above, are hereby authorized and approved upon the terms and conditions set forth in the application, subject to the provisions of this order.

(B) Columbus shall eliminate the electric plant acquisition adjustment which will be created by the transaction between Columbus and Midland by a charge to Account 216, Unappropriated Earned Surplus.

(C) Columbus and South-Central shall make determinations of the original cost and of the applicable accumulated provisions for the properties involved in the respective acquisitions from Midland and shall record the transactions herein authorized and the facilities and properties described above as provided in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees.

(D) This authorization shall expire unless the transactions hereby authorized are consummated within 90 days from the date of issuance of this order.

(E) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuations, estimates or determinations of costs, or any other matter whatsoever which is now pending or which may come before this Commission or any other regulatory body.

(F) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States in respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

SOUTH CAROLINA ELECTRIC & GAS COMPANY, PROJECT NO. 1894

ORDER APPROVING FACILITIES

(Issued May 9, 1962)

On March 8, 1962, South Carolina Electric & Gas Company, licensee for major Project No. 1894, filed application for approval of facilities for its Parr Shoals project on Broad River, South Carolina, to convert its operation from manual to remote control.

The licensee states that the installation of the remote control equipment will improve operations.

Upon completion of such installation, the licensee should file revised exhibits to reflect the addition of the remote control operating equipment, pursuant to Article 3 of the license for the project.

The Commission finds:

The installation and operation of the remote control operating equipment at the Parr Shoals project is desirable in the public interest.

The Commission orders:

(A) The installation and operation of the equipment mentioned in the above finding is approved.

(B) Pursuant to Article 3 of the license for Project No. 1894, the licensee shall, upon completion of the installation of the remote control operating equipment, file for Commission approval revised exhibits to reflect such installation, in conformity with the Commission's rules and regulations.

(C) This instrument in the manner set out above shall not operate to alter or amend the license in any other respect, and shall not in any way constitute a waiver of any other part, provision or condition of the license.

(D) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313(a) of the Federal Power Act and failure to file such an application shall constitute acceptance of this order. In acknowledgment of the acceptance of this order, it shall be signed for the licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Harold C. Woodward.

CONTINENTAL OIL COMPANY, DOCKET NO. G-11024; THE ATLANTIC REFINING COMPANY, DOCKET NO. G-11034; CITIES SERVICE PRODUCTION COMPANY, DOCKET NOS. G-11046, G-15330; TIDEWATER OIL COMPANY, DOCKET NO. G-11049

ORDER AMENDING ORDER GRANTING MOTION FOR STAY

(Issued May 10, 1962)

On March 12, 1962, this Commission issued an order in these consolidated proceedings granting in part a motion for stay filed by the applicants herein on February 12, 1962, 27 FPC, 498. By said order we stayed ordering paragraphs (B), (C) and (D) of the order accompanying Opinion No. 351, issued January 22, 1962, herein, for a period of 60 days following the Commission's final action upon any application for rehearing or reconsideration filed herein.

On April 23, 1962, the Applicants filed a joint and several motion requesting the Commission to amend its order of March 12, 1962, so as to extend the stay of said ordering paragraphs to (a) "30 days after conclusion of judicial review of the order accompanying the Commission's Opinion No. 351, issued January 22, 1962" or (b) "90 days after final action by the Commission upon the applications for rehearing filed in these proceedings."

We have reconsidered the motion filed by Applicants herein on February 12, 1962, the answer filed in opposition filed by Long Island Lighting Company on February 20, 1962, and the answer filed by the Public Service Commission of the State of New York on February 23, 1962 (both of which are more fully described in our order of March 12, 1962, aforementioned), and upon considera-

tion of the said motion to amend filed on April 23, 1962, we do not believe that the public interest will be adversely affected by deferring the payment of refunds, with interest, we have found to be proper in the order accompanying Opinion No. 351 for a period of 30 days after conclusion of judicial review of the said order, nor do we find that the public interest will be adversely affected by extending to Applicants a stay of 90 days from the date of our final action in these proceedings, i.e., the date of the issuance of our order denying rehearing which was March 22, 1962, to place into effect the rates set forth in ordering paragraph (B) of the said order accompanying Opinion No. 351, aforementioned.

The Commission finds:

Good cause exists for granting, in part, the motion filed by Applicants on April 23, 1962, for an amendment to the order issued herein on March 12, 1962, so as to stay the actions required by ordering paragraphs (C) and (D) for a period of 30 days after conclusion of judicial review of the order issued January 22, 1962, aforementioned, and to stay the effect of the conditions set forth in ordering paragraph (B) of said order until 90 days from the date of our order of March 22, 1962, aforementioned.

The Commission orders:

(A) The conditions and requirements set forth in ordering paragraph (B) of the order accompanying Opinion 351, issued January 22, 1962, to and as a part of the permanent certificates of public convenience and necessity issues thereby, are hereby stayed until 90 days from the date of the order denying rehearing issued herein on March 22, 1962.

(B) The completion of the acts and compliance with the requirements set forth in ordering paragraphs (C) and (D) of the said order accompanying said opinion, are hereby stayed for a period of 30 days after conclusion of judicial review of said order issued January 22, 1962.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

PACIFIC GAS & ELECTRIC COMPANY, PROJECT NO. 2106

ORDER TERMINATING HEARING AND AMENDING LICENSE

(Issued May 10, 1962)

This matter comes before the Commission at the request of the State of California and the licensee, Pacific Gas and Electric Company, and upon the recommendation of the Presiding Examiner after a prehearing conference called for the purpose of discussing the issues set forth in the order of October 19, 1961, granting the State's application for rehearing.

Question was raised as to certain conditions in the order of August 18, 1961, issuing a licensee under the Federal Power Act for the McCloud-Pit development in California.

These conditions would require the licensee to construct fish hatchery facilities, if after proper study and investigation such facilities are found by the Commission to be necessary and desirable for the protection of fishery resources, provide for ultimate determination of the responsibility for the costs of maintaining and operating such fish hatchery facilities, and require the licensee to make certain water releases down the Pit River below Pit 6 and Pit 7 dams for the preservation of fish and aquatic life.

The State of California and the licensee have now agreed upon the language to carry out those license conditions and have submitted it for our consideration.

The Commission finds:

The license conditions hereinafter imposed are necessary and desirable in the public interest to protect the aquatic and fish life in the area affected by the proposed development.

It is no longer necessary to have a hearing as provided in the order of January 30, 1962 and that order should be rescinded.

The Commission orders:

(A) The order of August 18, 1961 issuing a license under the Federal Power Act for Project No. 2106 is hereby amended by adding the following further conditions:

Article 47. (A) The Licensee shall construct such fish trapping, egg taking, hatching, rearing, and planting facilities in compensation for loss of spawning areas in the Pit River and in the interest of maintaining fish populations dependent upon said river, as may be required by the Commission after notice and opportunity for hearing; provided that such determination shall be made and the exact nature and capacity of such facilities shall be prescribed by the Commission after consideration of recommendations of the California Department of Fish and Game, the United States Fish and Wildlife Service and the Licensee based upon information developed during a period of not less than two or more than four years following the first year of impaired access of fish to the natural spawning grounds above Pit 6 and/or Pit 7; provided further that prior to such impaired access and during said period Licensee shall construct and operate or otherwise provide such temporary facilities as are required to protect and maintain the fish resource affected by the construction of the project; and provided further that the responsibility for providing the funds for operation and maintenance of said fish trapping, egg taking, hatching, rearing and planting facilities shall be as determined by the Commission, after notice and opportunity for hearing, at the same time that the nature and capacity of such facilities are prescribed.

(B) The Licensee shall maintain a flow of 150 c.f.s. at all times in the Pit River downstream from Pit 6 and Pit 7 dams for the preservation of fish and aquatic life; provided that after Pit 7 dam is completed and in operation the flow release shall be maintained only downstream from Pit 7 dam; provided further that at times when the pool of Shasta Lake is at an elevation as high or higher than the Pit 7 powerhouse draft tube invert only such releases as may be required for operation of fish handling facilities need be made.

(B) The order of January 30, 1962, fixing the time and place for hearing and prescribing procedure, is hereby rescinded.

(C) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313 (a) of the Act, and failure to file such an application shall constitute acceptance of this license amendment. In acknowledgement of the acceptance of this license amendment, it shall be signed for the Licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TRUNKLINE GAS COMPANY, DOCKET NOS. G–12884, G–19479, AND RP60–6

ORDER APPROVING RATE SETTLEMENT, PRESCRIBING REFUNDS AND TERMINATING PROCEEDINGS

(Issued May 10, 1962)

These proceedings arise under Section 4 of the Natural Gas Act and relate to increases and changes in rates and charges tendered for filing by Trunkline Gas Company (Trunkline), a wholly-owned affiliate of Panhandle Eastern Pipe Line Company (Panhandle).

The proceeding in Docket No. G–12884 principally concerns the revised tariff sheets tendered for filing by Trunkline on June 14, 1957, whereby it proposes to change the form of its rate for service to Panhandle from a cost of service rate form [1] to a demand-commodity or two-part rate form (P–1) together with an interruptible excess rate schedule (R–1). In addition, a new general service rate schedule (G–1) was also proposed, applicable to entire requirement loads in excess of 2,000 Mcf per day, but optional for customers taking less than 2,000 Mcf per day (receiving service under rate schedule SG–1). Trunkline stated that the proposed changes would result in no increase in charges over those resulting from the rates previously in effect. By order issued July 17, 1957, the Commission suspended these proposed changes until January 1, 1958, at which time they became effective subject to hearing and refund requirements.

The proceeding in Docket No. G–19479 concerns the proposed increased rates and charges tendered for filing by Trunkline on August 31, 1959. By order issued September 28, 1959, the Commission suspended the proposed increased rates and charges until March 1, 1960, at which time they became effective subject to hearing and refund requirements. In support of these proposed rates, the company asserted a need for an annual increase in jurisdictional revenues in its Zone 1 rates of $9,580,000.[2] In support of that increase Trunkline cited increased costs resulting from increased plant investment and higher prices for new gas supply and claimed a need for a 6¾ percent rate of return.

The proceeding in Docket No. RP60–6 relates to the proposed increased rates and charges tendered for filing by Trunkline on March 2, 1960. By order issued March 29, 1960, the Commission suspended the proposed increased rates and charges until July 1, 1960, at which time they became effective subject to hearing and refund requirements. In support of the proposed increased rates and charges, the company asserted a need for an annual increase in jurisdictional revenues of $5,365,000 over the rates subject to refund in Docket No. G–19479. The company based its claim entirely upon asserted increases in purchased gas costs and related increased severance taxes.

Upon the opening of the hearings which were convened in these consolidated proceedings on April 24, 1962, counsel for Trunkline Gas Company (Trunkline) submitted for the record a stipulation and agreement, dated April 19,1962, as subsequently amended,[3] together with a series of documents which represented Trunkline's cost of service studies. These documents had been submitted to all

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[1] Trunkline's cost of service rate form was prescribed by the Commission in *Trunkline Gas Supply Co., et al.*, order issued May 4, 1950, 9 FPC 721, 729.

[2] Sales at and south of Tuscola, Illinois, the termius of its system prior to the expansion and extension authorized by Opinion No. 321 in Docket No. G–15394. Zone 2 comprises the new extension north of Tuscola.

[3] Subsequent amendments reduced the SG–1 rate to 39.2 cents per Mcf and the SG–2 rate to 46.6 cents per Mcf, as shown on Appendix A, footnotes "1" and "2".

parties during a series of rate settlement conferences held in conference rooms of the Commission commencing March 20, 1962. Counsel for Trunkline requested that the Presiding Examiner certify the proposed settlement agreement to the Commission for its consideration and recommended that the rates and charges and refunds therein set forth be accepted and made effective as therein proposed.

Commission staff counsel also submitted for the record certain cost of service studies which had been prepared by the staff and submitted to all parties in the said conferences. Staff counsel then stated that the staff had agreed to the stipulation and agreement, as amended, and that the staff recommended that the settlement be approved by the Commission and made effective as requested. The record also reflects the agreement of all the parties represented at the hearing. No objections have been made to the proposed settlement.

The Presiding Examiner has certified to us the proposed settlement agreement and the record in these proceedings and has recessed the hearings subject to the further order of the Commission.

Briefly stated, the proposed settlement agreement provides as follows:[4]

(1) The rate schedules included in Appendix C to the settlement agreement include Rate Schedules P–1 and R–2, providing for a demand-commodity, or two-part, rate and an interruptible excess rate, respectively, for service to Panhandle, to become effective as of April 1, 1962. Likewise, additional rate schedules are included in Appendix C covering general service in Zone 1 (G–1), small general service in both Zones 1 and 2 (SG–1, SG–2), firm service in Zone 2 (P–2), and excess interruptible service in Zone 2 (R–2).[5] All rate schedules are proposed to become effective as of April 1, 1962.

(2) The rates and charges proposed by Trunkline subject to proceedings in Docket No. RP60–6 are reduced for gas delivered on and after April 1, 1962, as shown in Appendix A hereto, to provide a reduction in revenues in the annual amount of 4¼ million dollars, based upon the twelve months' test period ended June 30, 1961, as adjusted.

(3) Refunds in the total amount of $7,423,737.78 (Appendix D hereto), will be made covering deliveries of gas during the period July 1, 1960, through March 31, 1962. This refund results from the reduction in rates set forth in Appendix B hereto (based upon the test year ending June 30, 1961, as adjusted) for the period July 1, 1960 through December 31, 1961, and from the rates set forth in Appendix A hereto (not including footnotes "1" and "2" and based upon the test year ending June 30, 1961, as adjusted) for the period January 1, 1962, through March 31, 1962.

(4) Interest on the above refunds is to be paid at the rate of 7 percent per annum from the date of receipt by Trunkline of the revenues to be refunded to the date of payment to customers.

(5) Trunkline will also make refunds and reduce its rates if it receives refunds from its suppliers or such suppliers reduce their rates which are subject to the proceedings specifically set forth in Appendix E hereto. Such refunds and reductions are to be distributed in proportion to the volumes of customer purchases, provided, however, that no refunds are to be passed on by Trunkline

[4] For convenience only, Appendices A, B, D and E to the proposed agreement are attached hereto. The text of the agreement is summarized hereinafter. Appendix C contains the proposed revised tariff sheets, identical to those, tendered for filing on April 26, 1962.

[5] Rate Schedules P–1, R–1 and G–1 were originally tendered for filing in Docket No. G–12884. Rate Schedules P–2 and R–2 were originally tendered for filing pursuant to Opinion No. 321 and were made subject to these proceedings. Likewise, Rate Schedule SG–2 was originally tendered for filing pursuant to Opinion No. 339 and was made subject to these proceedings.

until they accumulate to the amount of $250,000 or more (except final refunds not less than $25,000); and also provided that such rate reductions are limited to reductions in the weighted Trunkline's average cost of purchased gas (18.26 cents per Mcf).

(6) Trunkline will not file for any increase in rates and charges so as to become effective, after suspension, prior to July 1, 1963, unless it has incurred or will incur within six months from the date of filing of such increased rates, increases in costs in the total amount of $400,000 per annum arising from either (a) new taxes or increases in tax rates, or (b) increases in rates paid gas suppliers over and above those effective March 30, 1962.

(7) By redefinition of the designation "Small General Service Buyer," the availability of the SG rates is increased from 2,000 Mcf per day to 4,000 Mcf per day.

The agreement also contains a request that the Commission waive compliance with its Rules and Regulations to the extent necessary to effectuate the settlement agreement, and a request that the Commission accept all the terms of the agreement as being essential to the mutuality of the agreement. Finally, no party is deemed to have approved or agreed to any ratemaking principle or method, and no party is to be prejudiced by agreement herein with respect to any other proceeding.

On April 26, 1962, Trunkline tendered for filing 13 revised tariff sheets identical to those included in Appendix C to the said agreement and requested that they be permitted to become effective as of April 1, 1962, pursuant to the agreement. These revised tariff sheets set forth the rates and charges contained in Appendix A hereto as well as the increased availability for Small General Service customers. These revised sheets are:

> Fifth Revised Sheet No. 4, First Revised Sheet No. 5–A; Fourth Revised Sheet No. 6–A, Third Revised Sheet No. 6–B; Second Revised Sheet No. 6–C, Fourth Revised Sheet No. 7; Fifth Revised Sheet No. 9, Second Revised Sheet No. 9–D; Second Revised Sheet No. 9–F, Third Revised Sheet No. 9–G; First Revised Sheet No. 9–P, First Revised Sheet No. 9–R; Second Revised Sheet No. 10.

In addition, the agreement provides that no modifications are required with respect to the following revised tariff sheets now effective subject to hearing and refund in these proceedings and that they should be permitted to remain in effect.

> Fifth Revised Sheet No. 5, Second Revised Sheet No. 6–D, Second Revised Sheet No. 8, Original Sheet No. 9–Q, Second Revised Sheet No. 24, Second Revised Sheet No. 31, and Second Revised Sheet No. 32.

The Commission finds:

(1) The proposed increased rates and charges which became effective July 1, 1960, subject to hearing and refund in Docket No. RP60–6, as hereinabove described, have not been shown to be just and reasonable, or otherwise lawful under the terms and provisions of the Natural Gas Act, and the tariff filings containing such rates and charges should be disallowed and denied as hereinafter provided and ordered.

(2) The settlement of these proceedings on the basis proposed and agreed to by the parties and certified to us by the Presiding Examiner for our consideration on April 25, 1962, as above described and as more specifically set forth in said stipulation and agreement, is reasonable and proper in the public interest in carrying out the provisions of the Natural Gas Act and such proposed settlement agreement should be approved and be made effective, subject to the terms and conditions hereinafter provided and ordered.

The Commission orders:

(A) The proposed increased rates and charges contained in rate filings referred to in paragraph (1) above, are disallowed and denied.

(B) The settlement of these proceedings on the basis and terms contained in the settlement agreement as hereinabove described, is approved and made effective, subject to the terms and conditions hereinafter ordered.

(C) Trunkline shall make refunds of excess charges to its jurisdictional customers, including interest thereon at 7 percent per annum, within fifteen days from the date of the issuance of this order, as provided in Article III of the said agreement and Appendix D hereto.

(D) Within 20 days after refunds have been made as provided in paragraph (C) hereof, Trunkline shall report to the Commission, in writing and under oath, the amount of the refunds made to each of its utility customers, and shall serve a copy of such report upon each of its customers receiving a refund. Concurrently therewith, Trunkline shall file with the Commission releases from its jurisdictional customers showing receipt of principal and interest so paid.

(E) Trunkline shall make future refunds and necessary rate reductions to reflect refunds and rate reductions of its suppliers, as provided in Article IV of said agreement, subject to approval by the Commission.

(F) The following 13 revised tariff sheets affecting Trunkline Gas Company's FPC Gas Tariff, Original Volume No. 1, as tendered for filing on April 26, 1962, are accepted for filing and shall become effective as of April 1, 1962:

Fifth Revised Sheet No. 4, First Revised Sheet No. 5–A, Fourth Revised Sheet No. 6–A, Third Revised Sheet No. 6–B, Second Revised Sheet No. 6–C, Fourth Revised Sheet No. 7, Fifth Revised Sheet No. 9, Second Revised Sheet No. 9–D, Second Revised Sheet No. 9–F, Third Revised Sheet No. 9–G, First Revised Sheet No. 9–P, First Revised Sheet No. 9–R, Second Revised Sheet No. 10

(G) The following 7 tariff sheets now on file are hereby permitted to remain in effect without being subject to refund requirements:

Fifth Revised Sheet No. 5, Second Revised Sheet No. 6–D, Second Revised Sheet No. 8, Original Sheet No. 9–Q, Second Revised Sheet No. 24, Second Revised Sheet No. 31, and Second Revised Sheet No. 32.

(H) Upon payment of the amounts of refunds provided in Article III of the agreement (Appendix D hereto), and upon compliance by Trunkline with the terms and conditions of paragraphs (C) and (D) of this order, the proceedings in Docket Nos. G–12884, G–19479 and RP60–6 shall be terminated, subject only to Trunkline's obligations under paragraph (E) and Article IV of the agreement.

(I) Nothing contained in this order shall be construed as a waiver of the requirements of Section 7 of the Natural Gas Act, as amended; nor shall it be construed as constituting approval by this Commission of any service, rate, charge, classification, or any rule, regulation, contract or practice affecting such service or rate provided for in the above-described tariff sheets; nor shall this order be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate.

(J) This order is without prejudice to any findings or orders which have been or may hereafter be made by the Commission and is without prejudice to any claims or contentions which may be made by the Commission, Trunkline, the Commission staff, or any other party affected by this order, in any proceeding now pending or hereafter instituted by or against Trunkline Gas Company or any other persons or parties affected by this order.

APPENDIX A

TRUNKLINE GAS COMPANY

Rates for future—RP60–6

(Test period reduction—$4¼ million)

Rate schedule	RP60–6 filed rates	Settlement rates	Revenues		
			Present rates	Settlement rates	Reduction
Zone 1:					
P–1 Demand	$3.31	$2.69	$13,703,400	$11,136,600	$2,566,800
Commodity	.259	.261	32,503,830	32,754,825	(250,995)
G–1 Demand	2.30	2.19	138,000	131,400	6,600
Commodity	.284	.275	197,596	191,334	6,262
SG–1	.427	[1].408	1,161,105	1,079,211	81,894
R–1	.367	.349	2,046,186	1,945,828	100,358
Total Zone 1			49,750,117	47,239,198	2,510,919
Zone 2:					
P–2 Demand	3.54	2.98	5,564,880	4,684,560	880,320
Commodity	.318	.300	15,031,065	14,180,250	850,815
SG–2	.490	[2].482			
R–2	.434	.398			
Total Zone 2			20,595,945	18,864,810	1,731,135
Total			70,346,062	66,104,008	4,242,054

[1] The SG–1 rate is to be 39.2 cents per Mcf effective April 1, 1962. The future rates effective April 1, 1962, result in an annual reduction in revenues of $4,281,376 based on the test period.
[2] The SG–2 rate is to be 46.6 cents per Mcf effective April 1, 1962.

APPENDIX B

Rates for refund—RP60–6, July 1, 1960 through December 31, 1961

(Test period reduction—$3.6 million)

Rate schedule	RP60–6 filed rates	Settlement rates effective 7/1/60 to 12/31/61	Revenues		
			Present rates	Settlement rates	Reduction
Zone 1 [1]					
Zone 2:					
P–2 Demand	$3.54	$3.18	$5,564,880	$4,998,960	$565,920
Commodity	.318	.307	15,031,065	14,511,123	519,942
SG–2	.490	.490			
R–2	.434	.411			
Total Zone 2			20,595,945	19,500,083	1,085,862
Total Zone 1 reduction from Appendix A					2,510,919
Total reduction					3,596,781

[1] Same as Appendix A.

APPENDIX D

Refunds—Docket No. RP60–6, July 1, 1960 thru March 31, 1962

Rate schedules P–1 and R–1:	
Panhandle Eastern Pipe Line Company	$4,561,350.00
Mississippi River Transmission Corp	379,758.31
Illinois Power Company	62,208.60
Total rate schedules P–1 and R–1	5,003,316.91
Rate schedules P–2 and R–2:	
Consumers Power Company	2,041,617.84
Michigan Gas Utilities Company	87,428.08
Northern Indiana Public Service Co	173,529.55
Total rate schedules P–2 and R–2	2,302,575.47
Rate schedule G–1:	
Central Illinois Public Service Co	26,084.49
Southeastern Illinois Gas Company	14,222.89
Fairfield, Illinois	11,575.12
Total rate schedule G–1	51,882.50
Rate schedule SG–1:	
Boyce, Louisiana	1,990.61
Colfax, Louisiana	2,781.89
Union Gas Company	2,133.80
Byhalia, Mississippi	5,929.76
Somerville, Tennessee	3,100.01
Newbern, Tennessee	2,640.47
Trimble, Tennessee	825.24
Obion, Tennessee	2,023.96
Troy, Tennessee	1,090.11
Lake County Utility District	8,498.23
Hickman, Kentucky	3,877.94
Clinton, Kentucky	1,773.04
Bardwell, Kentucky	1,322.01
Wickliffe, Kentucky	1,571.52
LaCenter, Kentucky	1,148.41
Vienna, Illinois	2,370.23
McLeansboro, Illinois	6,828.45
Village of Wayne City, Illinois	1,776.88
Fairfield, Illinois	126.00
Flora, Illinois	9,876.80
Citizens Gas Company	3,484.09
Total rate schedule SG–1	65,169.45
Rate schedule SG–2:	
Central Illinois Electric & Gas Co. (Sidney)	247.83
Central Illinois Electric & Gas Co. (St. Joseph)	94.97
Rensselaer, Indiana	450.65
Total rate schedule SG–2	793.45
Total refund for all rate schedules	7,423,737.78

APPENDIX E

Producer rates subject to FPC action

Producer	FPC rate schedule	Docket No.
Rate increases under Section 4		
Amerada Petroleum Corporation	14	RI60-18
Bel Oil Corporation	4	G-14259
Cities Service Petroleum Company	1	G-15210, RI60-143
Delhi Taylor Oil Corporation	1	G-20429, G-20430
Paul J. Fly, *et al.*	1	G-20207
J. R. Goff, Trustee	1	G-14053, G-17527, G-20441, RI60-472
H. L. Hunt	13	G-13837, G-17163 G-20340, RI60-427
L. B. Hunt Estate	2	G-13840, G-17162, G-20445, RI60-432
Claude M. Langton, Trustee	1	G-14054, G-17164, G-20456, RI60-428
W. C. McBride	1	G-16890
Mobil Oil Company	41	G-14068, G-17622, G-20343, RI60-422
	52, 162	G-20344
D. N. Penton, *et al.*	1	G-17800
Petroleum Inc.	13	G-20276, RI61-295
Rouse Well Service	1	G-18846
Secure Trusts	2	G-13839, G-17161, G-20455, RI60-429
Sun Oil Company	80	G-13937, G-17346, G-20447, RI60-410
Superior Oil Company	1	G-18168, G-20435
	3	G-20577
The Texas Company	190	G-20433
Texas Gulf Producing Company	2	G-16177, RI60-204
	4	G-16240, RI60-204
	22	G-14069, G-17373, RI60-402
	23	G-14112, G-17372, RI60-403
C. B. Webster	2	G-14187
Tax reimbursement subject to FPC action[1]		
Pan American Petroleum Corporation	258, 259, 260	G-20288
Austral Oil Exploration Company, *et al.*	13	G-20289
Robert Mosbacher, *et al.*	2	G-20290
Union Oil Company of California	40	G-20287

[1] Proceedings limited to tax reimbursement by FPC order of December 23, 1959.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

COOS-CURRY ELECTRIC COOPERATIVE, INC., PROJECT NO. 2172

ORDER PERMITTING WITHDRAWAL OF APPLICATION FOR LICENSE (MAJOR) AND TERMINATING PROCEEDING

(Issued May 11, 1962)

On May 21, 1958, Coos-Curry Electric Cooperative, Inc. (Applicant), filed an application for license for proposed major Project No. 2172 to be located on the Illinois River at the Bald Mountain site, in Curry and Josephine Counties, Oregon.

In October 1960, Applicant advised us that it had abandoned its plans for development of the Bald Mountain site and was making studies of a site downstream from the Bald Mountain site, and upon completion of its studies, Applicant would amend its pending application to embrace the alternate development

and abandon the Bald Mountain development. Further correspondence concerning the matter between Applicant and our staff culminated in the filing by Applicant on March 26, 1962 of an application for withdrawal of its long-pending application for license for Project No. 2172.

The State of Oregon, acting by and through the Oregon State Game Commission and the Fish Commission of Oregon, was permitted to intervene in this proceeding by our order issued November 3, 1958.

The Commission finds:

It is appropriate to permit the withdrawal of the afore-mentioned application for license.

The Commission orders:

Permission to withdraw the afore-mentioned application for license for proposed Project No. 2172 is granted and this proceeding is hereby terminated.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

THE MONTANA POWER COMPANY, PROJECT NO. 5

ORDER APPROVING PROJECT EXHIBITS

(Issued May 11, 1962)

On June 26, 1959, The Montana Power Company, licensee for major Project No. 5 on the Flathead River, Montana, filed for Commission approval substitute drawings of Exhibit L, Sheets 2 of 5, 3 of 5, and 5 of 5, and an amendment to supplemental Exhibit M. The changes shown by these filings related to the use of one 60,000 kilovolt-ampere three-phase transformer in lieu of three single-phase transformers for the third generating unit. The purpose of the changes is to conserve space.

Commission consideration of the above-described filings was delayed pending the conclusion of the proceeding on an application for amendment of the license for Project No. 5 to include a third generating unit and a determination of additional Indian rentals in connection therewith.

The above-mentioned Exhibit L, Sheet 5 of 5 is a one-line wiring diagram for the third unit, which requires no Commission approval.

The Commission finds:

(1) The following described substitute Exhibit L drawings and amendment to Exhibit M conform to the Commission's rules and regulations and should be approved as part of the license for the project, as hereinafter provided:

Exhibit L	Number		Title
	FPC	Company	
Sheet 2 of 5	5-119	F-117098	Powerhouse extension for 3d unit.
Sheet 3 of 5	5-120	F-117099	Section thru 3rd unit.

and "Amendment to Supplemental Exhibit 'M', General Description of Plant and Equipment".

(2) The following described Exhibit L drawings, now part of the license for the project and which have been superseded, should be eliminated from the license for the project, as hereinafter provided:

Exhibit L	Number		Title
	FPC	Company	
Sheet 2 of 5	5-110	F-117098	Powerhouse plans.
Sheet 3 of 5	5-111	F-117099	Powerhouse cross section.

The Commission orders:

The substitute Exhibit L drawings and amendment to Exhibit M described in finding (1) above are approved as part of the license for Project No. 5, and the superseded Exhibit L drawings described in finding (2) above are eliminated from the license for the project.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

PACIFIC GAS & ELECTRIC COMPANY, PROJECT NO. 2105

ORDER APPROVING REVISED EXHIBIT L DRAWING

(Issued May 11, 1962)

On February 6, 1962, Pacific Gas and Electric Company, licensee for major Project No. 2105, filed for Commission approval a revised Exhibit L drawing relating to the Lake Almanor development of the project.

The revised drawing proposes various alterations to the Lake Almanor earthen dam to reduce water percolation and the possibility of local slides. The proposed alterations would consist of: flattening of the upstream slope of the dam; provision for additional grouting of the foundation of the dam; installation of steel sheet pile cut-off and additional compacted earth fill near the upstream portion of the dam in order to create an impervious barrier; and other miscellaneous changes.

Before the license for Project No. 2105 was issued, it was recognized that the Lake Almanor dam required certain corrective measures to reduce water percolation through it if operated at elevation 4,500 feet as provided for in the license. Consequently, the project has been operated with a maximum water surface elevation of 4,474 feet.

Construction of new peaking hydroelectric plants by the licensee has made it desirable to operate its hydroelectric plants on the North Fork Feather River at a higher load factor to maximize the hydroelectric dependable capacity of the licensee's system. This requires the use of more storage capacity at Lake Almanor to increase the low flows available for power.

The gain in system dependable capacity, as a result of raising the maximum water surface at Lake Almanor to elevation 4,500 feet, amounts to at least 100,000 kw valued at about $2,000,000 per year. The capital cost of modifying the Lake Almanor dam is estimated at $6,750,000 and the annual cost at about $800,000. Since the annual benefits exceed the annual costs, it is economical to modify Lake Almanor Dam so as to permit the physical operation of the water surface to elevation 4,500 feet.

Lake Almanor, one of the largest artificial bodies of water in California, lies within both the Plumas and Lassen National Forests. Since construction of the original Lake Almanor dam about 30 years ago, the shoreline has been developed for recreational purposes, including many cottages, a large campground on the shore of the lake maintained by the U.S. Forest Service, and a small community known as Chester situated close to the shoreline. Hence, it does not appear feasible to consider a higher elevation for the water surface of Lake Almanor than that provided for in the license, namely, 4,500 feet.

The alterations to the Lake Almanor dam were planned to commence this past March with completion by December, 1963.

The Commission finds:

The following described revised Exhibit L drawing conforms to the Commission's rules and regulations and should be approved as part of the license for Project No. 2105, and Exhibit "K–2", entitled "Enlargement of Lake Almanor Dam, Map and Cross-Section of Dam" (FPC No. 616–3), now part of the license, and which is superseded, should be eliminated from the license—all as hereinafter provided:

Exhibit L–1A entitled "Alterations to Lake Almanor Dam, Plan and Cross Sections" (FPC No. 2105–13).

The Commission orders:

The revised Exhibit L drawing described in the above finding as conforming to the Commission's rules and regulations is approved as part of the license for Project No. 2105, and the Exhibit K drawing described in the same finding as being superseded is eliminated from the license for the project.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

CITY OF SLATER, MISSOURI, DOCKET NO. CP61–337

ORDER GRANTING PERMISSION FOR WITHDRAWAL OF APPLICATION

(Issued May 11, 1962)

On April 26, 1962, the City of Slater, Missouri (Applicant), filed a notice of withdrawal of its application herein.

Said notice of withdrawal recites that hearings have been held on said application on April 9, 10 and 11, 1962, during which extensive evidence was developed of record pertaining to the delivery capacity of Cities Service Gas Company's Ottawa-Sedalia-Carrollton main transmission line and the Marshall, Missouri lateral. Said hearings are now scheduled to resume on May 8, 1962, for presentation of rebuttal evidence by Applicant and cross examination by other parties.

Applicant alleges, among other things, that since the close of the hearings herein, Applicant has considered the evidence adduced and has concluded that further prosecution of its application would be inimical to its interests, and that termination of this proceeding would not only redound to the benefit of the citizens of Slater, but would also be in the general public interest.

The Commission finds:

Good cause has been shown for permitting the City of Slater, Missouri to withdraw its application herein.

736–330—64——62

The Commission orders:

The City of Slater, Missouri be and it is hereby permitted to withdraw its application herein, without prejudice to its right to refile said application at some appropriate time in the future or its right to intervene in an appropriate Cities Service Gas Company's expansion proceeding for the purpose of obtaining an allocation of gas.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

SUN OIL COMPANY, DOCKET NOS. G–6650 AND RI62–418; SOUTH-TEX CORPORATION, DOCKET NO. RI62–419; ASSOCIATED OIL & GAS COMPANY, DOCKET NO. RI62–420

ORDER GRANTING REHEARING, REINSTATING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, TEMPORARILY REACCEPTING RATE SCHEDULE, PROVIDING FOR HEARING ON AND SUSPENSION OF PROPOSED CHANGE IN RATE, ALLOWING RATE CHANGE TO BECOME EFFECTIVE SUBJECT TO REFUND, AND TO SHOW CAUSE

(Issued May 11, 1962)

On April 12, 1962, Sun Oil Company (Sun) filed in Docket No. G–6650, an application for rehearing of the action of the Secretary of the Commission[1] whereby he rescinded the prior acceptance of Sun's FPC Gas Rate Schedule No. 31, and vacated the certificate of public convenience and necessity which authorized the sale of natural gas under said rate schedule. The sales of natural gas involved herein are made pursuant to an agreement, dated November 1, 1953, between Sun and South-Tex Corporation (South-Tex) whereby the parties agreed that South-Tex would process all of the gas produced from Sun's E. M. Brownlee Lease, Nueces County, Texas, and would deliver the quantity of residue gas equal to 95% of the daily quantity of gas delivered by Sun to South-Tex to Tennessee Gas Transmission Company under South-Tex's sales contract with Tennessee.

On November 30, 1954, Sun filed with the Commission its November 1, 1953 contract with South-Tex, and related documents, which were accepted for filing and designated as said Rate Schedule No. 31. Concurrently, Sun filed its application for a certificate of public convenience and necessity authorizing it to continue the afore-mentioned sales of natural gas to Tennessee. On May 28, 1956, the Commission issued an order in Docket No. G–6650, granting such certificate authority.[2]

On October 24, 1960, South-Tex filed a proposed increased rate for the gas delivered by it to Tennessee, except for that portion of the gas it was delivering on behalf of Sun. South-Tex did not file on behalf of Sun because Sun's portion of the gas was delivered under Sun's own Rate Schedule No. 31. South-Tex's proposed increased rate was suspended by order of the Commission in Docket No. RI61–243 until May 1, 1961.[3]

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[1] See § 3.5(a)(23), Subchapter A—General Rules, 18 CFR 3.5 (a)(23).

[2] *Howard W. Fleet, et al.*, Docket Nos. G–3275, *et al.*

[3] On March 6, 1961, South-Tex submitted an offer of settlement in Docket No. RI61–243. The offer of settlement did not cover that portion of the gas delivered by South-Tex to Tennessee on behalf of Sun. By order issued April 6, 1961, the Commission accepted and approved the offer of settlement made by South-Tex. The Commission's order recognized that Sun's gas was excluded from the settlement.

On December 22, 1960, Sun filed a proposed increased rate for its portion of the gas delivered by South-Tex to Tennessee. Sun designated such filing as Supplement No. 10 to its Rate Schedule No. 31. Pursuant to Section 154.91 (d) of the Commission's Regulations Under the Natural Gas Act, the Secretary by letter of January 18, 1961, rejected Sun's proposed rate increase without prejudice to its resubmittal if and when Sun establishes signatory status to the contract between South-Tex and Tennessee. Additionally, the Secretary advised Sun that its Rate Schedule No. 31 was subject to rejection, and the certificate covering said sale subject to being vacated, pursuant to the aforesaid Section 154.91(d). However, the Secretary took no action at that time, affording Sun thirty days in which to comment. On February 14, 1961, Sun advised the Commission by letter that it was taking action on the matter and would make supplemental filings.

On February 6, 1961, Sun by letter requested Tennessee to enter into a ratification agreement with it covering Sun's portion of the gas delivered by South-Tex to Tennessee. In response, Tennessee advised Sun by letter, dated February 27, 1961, that it did not wish to enter into such a ratification agreement with Sun.

On July 14, 1961, the Secretary of the Commission wrote to Sun making inquiry about the supplemental filings Sun had stated, on Febraury 6, 1961, that it would make. Sun did not respond until September 28, 1961, and then it filed an instrument which is no more than an affirmation of Sun's averment that South-Tex is its agent for the purpose of processing and delivering natural gas to Tennessee under South-Tex's sales contract. Consequently, the Secretary of the Commission, on March 13, 1962, rejected Sun's Rate Schedule No. 31, and vacated the certificate issued it in Docket No. G–6650.

In its afore-mentioned application for rehearing, Sun now advises the Commission that Sun "believes" Associated Oil and Gas Company (Associated) has succeeded "to all the rights and duties of South-Tex", and that it, Sun, wrote Associated on March 23, 1962, to request Associated to file Sun's proposed rate increase on Sun's behalf.[4] Sun avers that Associated refused so to do. Concurrently, Sun requested South-Tex to file Sun's proposed rate increase. On April 9, 1962, South-Tex declined to file for Sun. Sun's application for rehearing merely avers that Sun "believes" Associated succeeded to the processing plant of South-Tex. No filings have been made with the Commission by South-Tex or Associated to indicate such a transfer or acquisition.

Upon review of all of the above circumstances, and the due consideration of the same, we find that it is proper to grant Sun a rehearing of this matter. Therefore, we shall accept Sun's FPC Gas Rate Schedule No. 31, at least until the date of the final order in this matter, we shall reinstate Sun's certificate of public convenience and necessity previously granted Sun in Docket No. G–6650, until the date of final order in this matter, we shall permit Sun to file its proposed change in rate (Supplement No. 10 to its Rate Schedule No. 31) suspend the same, and order a hearing thereon. The increased rates and charges so proposed may be unjust, unreasonable, unduly discriminatory, or preferential, or otherwise unlawful. Additionally, because Sun evidently does not now know whether South-Tex or Associated is now receiving, processing and delivering its gas to Tennessee, but avers it "believes" it is now Associated, and because the files of the Commission show that it is South-Tex, we shall institute show cause proceedings against South-Tex and Associated to determine (1) if there has been any transfer of jurisdictional facilities without

[4] By letter dated April 18, 1962, Associated advised the Commission that it is not the successor to South-Tex as Sun avers.

Commission authorization, and (2) why the operator of the processing plant, whether it be South-Tex or Associated refuses to comply with Section 154.91 (b) of this Commission's regulations which requires an operator who is a signatory party to a gas sales contract to make rate filings for non-signatory co-owners.

The Commission orders:

(A) The application for rehearing filed by Sun on April 12, 1962, in Docket No. G–6650, is hereby granted, and the proceedings are hereby reopened for further proceeding.

(B) The certificate of public convenience and necessity granted Sun in Docket No. G–6650 on May 28, 1956, which was vacated by action of the Secretary of the Commission on March 13, 1962, is hereby reinstated until final order of the Commission in this matter.

(C) Sun's FPC Gas Rate Schedule No. 31, as supplemented, is hereby reaccepted for filing, and will remain in force and effect until final order of the Commission in this matter.

(D) The proposed increased rate filed by Sun on December 22, 1960, as Supplement No. 10 to its FPC Gas Rate Schedule No. 31, and re-tendered by it on April 12, 1962, is hereby accepted for filing, *Provided, However*, pursuant to the authority of the Natural Gas Act, particularly Sections 4 and 15 thereof, the Commission's Rules of Practice and Procedure, and the Regulations under the Natural Gas Act, a hearing shall be held upon a date to be fixed by notice from the Secretary concerning the lawfulness of the proposed change in rate and charges contained in Sun's Supplement No. 10.

(E) Pending hearing and decision thereon, the above-designated rate supplement is hereby suspended in Docket No. RI62–418 and the use thereof deferred until May 14, 1962, and thereafter until such further time as it is made effective in the manner prescribed by the Natural Gas Act.

(F) Upon making the proposed increased rate effective, in accordance with the provisions of the Natural Gas Act, concurrently therewith Sun shall file, with the Secretary of the Commission, its agreement and undertaking to comply with the refunding and reporting procedures required by the Natural Gas Act and Section 154.102 of the Regulations thereunder, together with a certificate showing service of a copy of the same upon Tennessee.

(G) South-Tex in Docket No. RI62–419 and Associated in Docket No. RI62–420 shall show cause, if any there be, under oath and in writing, within thirty days from the issuance of this order why the Commission should not find and determine upon the allegations and averments made by Sun.

(1) That South-Tex has transferred or conveyed facilities used for the sale of natural gas within the jurisdiction of this Commission to Associated, and that Associated has acquired the same, all without having received the authority of this Commission so to do in compliance with the provisions of the Natural Gas Act.

(2) That South-Tex and Associated, or either of them, have refused and declined to comply with Section 154.91(b) of the Commission's Regulations under the Natural Gas Act, in that they have refused or declined to make or tender to this Commission a proposed rate change on behalf of a non-signatory co-owner when requested by such so to do, and that this action by them, or either of them, constitutes a willful and knowing violation of the Natural Gas Act.

(H) That public hearings regarding the matters for which South-Tex and Associated are hereby ordered to show cause, and the proceedings thereon, shall be consolidated with Docket No. G–6650, and shall convene at the time and place fixed by the notice of the Secretary provided for in Paragraph (D) above.

(I) Notices of intervention or petitions to intervene may be filed with the Federal Power Commission, Washington 25, D.C., in accordance with the Rules of Practice and Procedure (18 CFR 1.8 or 1.37(f)) on or before June 27, 1962.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

AREA RATE PROCEEDING, DOCKET NO. AR61–1, CLAUDE E. AIKMAN, DOCKET NO. G–18466, ET AL.; NORTH CENTRAL OIL CORPORATION (OPERATOR), ET AL., DOCKET NO. CI60–435, ET AL.

ORDER DENYING MOTION AND AMENDING, IN PART, ORDER RELATING TO THE TYPE OF EVIDENCE TO BE CONSIDERED IN AREA RATE PROCEEDING

(Issued May 14, 1962)

On April 16, 1962, the People of the State of California and the Public Utilities Commission of the State of California (California) filed a motion requesting that copies of Appendices A and B filed by respondents in compliance with our order of August 2, 1961, herein, be made available to California, or alternatively that those of Phillips Petroleum Company and Shell Oil Company be made available. Our order of August 2, required the filing of data set forth in Appendices A and B, provided for compilation of the data in composite form by the Commission staff for introduction in the proceedings, and specified that the data should not be available to the parties until the data in composite form have been introduced in evidence in these proceedings. We stated that thereafter the individual filings would be made available to all parties to the proceedings.

Answers opposing the motion were filed jointly by Texaco Inc., Tidewater Oil Company, Continental Oil Company, Gulf Oil Corporation, The Superior Oil Company, and Humble Oil & Refining Company, and severally by Shell Oil Company, Sun Oil Company, Phillips Petroleum Company and the Commission staff.

California states that if it gains access to the data at this time it can begin work on its studies and exhibits and thereby expedite the proceedings. The staff answer points out that it proposes to make the composite data from Appendices A and B available in June of this year and has so announced on the record in these proceedings, while California's request anticipates receipt of the composite data in September.

Release of some or all of the Appendices at this time would not be in the interest of orderly procedure, would constitute an undue administrative burden on the Commission staff, and might prolong the time required for preparation of the data in composite form. Moreover, access to the data should be granted to all parties to the proceedings at the same time. For the foregoing reasons, California's motion to modify our order of August 2, 1961, should be denied.

The staff answer states that portions of the compilations have been identified and distributed to the parties in advance of introduction in the record and that it will continue to distribute other portions as they are completed. When all compilations under either Appendix are completed, distributed to the parties and identified in the record, the individual responses should be made available to the parties, even though the compilations have not technically been admitted in evidence in the proceedings.

By their answers Texaco *et al.* and Shell object to California's request since they state that the data are to be used in the preparation of rate base cost-of-service studies, which, under our order of April 5, 1961, herein, are not admissible in evidence. The order of April 5 did so provide, and we adhere to such

ruling insofar as rate base cut-of-service studies relate to the operations of an individual producer. However, we do not believe that the parties should be deprived of the opportunity to introduce in evidence composite rate base cost-of-service studies relating to a significant segment of industry operations in this area, and our order of April 5 is modified to the extent necessary to permit introduction of such evidence. Such composite studies may not suffer from the deficiencies which exist in individual company studies of this type. The value of such studies to our ultimate determinations in this proceeding or the weight, if any, to be accorded composite rate base cost-of-service studies must be determined on the whole record of the proceeding.

The Commission orders:

(A) The California motion filed April 16, 1962, herein, is hereby denied.

(B) Our orders of April 5, 1961 and August 2, 1961, herein, are hereby modified to the extent inconsistent herewith

Commissioner Ross although not present when this order was adopted asked that he be recorded in favor of the order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

COLORADO-WYOMING GAS COMPANY, DOCKET NO. CP62-149

FINDINGS AND ORDER PERMITTING AND APPROVING ABANDONMENT OF FACILITIES AND ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 14, 1962)

On December 15, 1961, as supplemented on February 15, 1962, Colorado-Wyoming Gas Company (Applicant) filed in Docket No. CP62-149 an application pursuant to Sections 7(b) and 7(c), respectively, of the Natural Gas Act for permission and approval to abandon facilities and for a certificate of public convenience and necessity to construct and operate the following facilities:

1. Approximately 8 miles of 8-inch transmission line around the City of Fort Collins, Colorado;

2. Approximately 1.5 miles of 4-inch transmission lateral extending from a point near the Ideal Cement Company plant meter station to Applicant's existing La Porte Town Border Station in Larimer County, Colorado;

3. A meter station at or near the north bank of the Cache La Poudre River in the NW¼ of Section 12, Township 7 North, Range 69 West, Larimer County, Colorado;

4. During 1962, mainline taps to render service to existing customers, at a total cost not to exceed $15,000, with no single tap to exceed a cost of $2,000; and

5. During 1962, facilities consisting of minor system reinforcements, extensions, relocations, and related facilities as may be required to render service to existing customers at a total cost not to exceed $50,000, with no single project to exceed a cost of $20,000.

Applicant seeks permission and approval to abandon the following facilities:

1. Approximately 5.15 miles of transmission line and related metering and other facilities located in and near the City of Fort Collins, Colorado;

2. Approximately 1.5 miles of existing 2-inch transmission lateral extending from a point near the Ideal Cement Company plant meter station to Applicant's existing La Porte Town Border Station in Larimer County, Colorado;

3. The Reynolds Beasley Group Tap (Station 2221+08) along the route of Applicant's 8-inch line in Boulder County, Colorado; and

4. The Grosball Tap (Station 26+63) near the westerly terminum of Applicant's 6-inch Loveland-Greeley lateral in Larimer County, Colorado.

Applicant sells natural gas from its Mesa-Boulder transmission line to Public Service Company of Colorado (Public Service) through a number of meter stations, for resale and distribution in and around Fort Collins. The Mesa-Boulder line must be operated at a high pressure in order to maintain adequate service for the retail customers farther north. Since a 5.15-mile section of this line traverses the recently urbanized area in and around Fort Collins, Applicant proposes to construct and operate a new 8-mile 8-inch line that will by-pass this congested area and tie in with the Mesa-Boulder line north of Fort Collins where a new meter station will be constructed. The 5.15-mile section, together with 8 meter stations, group taps, and farm taps thereon, will be abandoned by sale to Public Service for use in local distribution. The new meter station, along with the existing meter station located south of Fort Collins, will be used by Applicant to supply the distribution requirements of Public Service in Fort Collins and adjacent areas. The proposed relocations will eliminate the hazard of excessively high pressures being carried by one of Applicant's oldest lines on its system through a highly urbanized area.

The Reynolds Beasley and Grosball farm taps, located on the Mesa-Boulder line south of Fort Collins, will be abandoned since they are no longer in use. The areas previously served by Public Service through said taps are now being served by Public Service through its distribution facilities.

The 1.5 miles of 4-inch lateral line which Applicant proposes to construct will be used to replace an existing 2-inch lateral which Applicant proposes to abandon. The existing line is now and the proposed line will be used to supply Public Service with gas for resale and local distribution. The distribution load in this area has almost doubled during the year 1961, and the proposed line is necessary in order to meet the increased requirements and the anticipated load growth in the future.

Applicant also requests authorization to construct and operate unspecified minor "budget-type" farm tap facilities during the calendar year 1962 to enable Applicant to assure adequate natural gas service to existing resale customers in existing market areas and to relocate existing transmission facilities when necessary to make way for highway construction.

The total estimated cost of all the proposed construction, including the "budget-type" facilities, is $352,100, which will be financed from working funds and short term loans from Public Service. Public Service will pay Applicant the net book cost, less depreciation, of the facilities proposed to be transferred, which is estimated to be $21,380.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 1, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Colorado-Wyoming Gas Company, a Delaware corporation having its principal place of business in Denver, Colorado, is a "natural-gas company" wherein the meaning of the Natural Gas Act as heretofore found by the Commission in its order of June 5, 1945, in Docket No. G-285 (4 FPC 938).

(2) The proposed facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportion and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) The construction and operation of the proposed facilities by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(4) Applicant is able and willing to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and, regulations of the Commission thereunder.

(5) The facilities to be abandoned, as hereinbefore described, and as more fully described in the application, as supplemented, in this proceeding, are subject to the jurisdiction of the Commission, and abandonment of said facilities is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(6) Such abandonment by Applicant is permitted by the public convenience and necessity, and an order permitting and approving same should be issued as hereinafter ordered.

(7) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations; and further, with regard to the construction and operation of the facilities other than the "budget-type" facilities, the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with the general terms and conditions set forth in paragraphs (b), (c)(3), and (c)(4) of Section 157.20 of such Regulations.

(8) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit for the "budget-type" facilities, on or before March 1, 1963, a statement under oath showing by project: (a) location of said project or projects, (b) description of said project or projects, (c) the resale customer served by said project or projects, (d) facilities relocated, if any, (e) use to which the gas is to be put, and (f) the actual final cost of the facilities constructed.

(9) The "budget-type" authorization hereinafter granted should be limited to construction during the calendar year 1962. The total cost of the miscellaneous relocation facilities should be limited to a maximum of $50,000, with no single project to exceed a cost of $20,000; the total cost of the unspecified taps should be limited to a maximum of $15,000, with no single tap to exceed a cost of $2,000. The "budget-type" facilities should be used only for sales to authorized resale customers within the effective contract demand or delivery obligations set forth in Applicant's FPC Gas Tariff.

(10) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Colorado-Wyoming Gas Company, to construct and operate the proposed facilities, as hereinbefore described and as more fully de-

scribed in the application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of such Regulations; and further, with regard to the construction and operation of the facilities other than the "budget-type" facilities, the certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with the general terms and conditions set forth in paragraphs (b), (c) (3), and (c) (4) of Section 157.20 of such Regulations.

(C) The facilities hereby authorized, other than the "budget-type" facilities shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 6 months from the date on which this order issues.

(D) The "budget-type" authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962. The total cost of the miscellaneous relocation facilities is limited to a maximum of $50,000, with no single project to exceed a cost of $20,000; the total cost of the unspecified taps is limited to a maximum of $15,000, with no single tap to exceed a cost of $2,000. The "budget-type" facilities are to be used only for sales to authorized resale customers within the effective contract demand or delivery obligations set forth in Applicant's FPC Gas Tariff.

(E) Applicant shall submit for the "budget-type" facilities, on or before March 1, 1963, a statement under oath showing by project: (a) location of said project or projects, (b) description of said project or projects, (c) the resale customer served by said project or projects, (d) facilities relocated, if any, (e) use to which the gas is to be put, and (f) the actual final cost of the facilities so constructed.

(F) Permission for and approval of the abandonment by Applicant of the facilities hereinbefore described, as more fully set forth in the application, as supplemented, in this proceeding, be and the same is hereby granted.

(G) Applicant shall advise the Commission of the date of the abandonment within 30 days from the date thereof.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

THE OHIO FUEL GAS COMPANY, DOCKET NO. CP62-26

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND PERMITTING AND APPROVING ABANDONMENT

(Issued May 14, 1962)

On July 31, 1961, as supplemented on September 25, November 2, and December 13, 1961, The Ohio Fuel Gas Company (Applicant) filed an application pursuant to Section 7 of the Natural Gas Act for permission and approval to abandon resale natural gas service to Ohio Gas Company (Ohio Gas) for its Millersburg Division, Holmes and Coshocton Counties, Ohio; and for a certificate of public convenience and necessity authorizing the acquisition and operation of certain jurisdictional facilities of Ohio Gas' Millersburg Division in Holmes County.

Applicant states that all of the Millersburg Division properties of Ohio Gas will be acquired and operated by Applicant. Specifically, the jurisdictional facilities involved are:

> Approximately 26,050 feet of 6-inch pipeline, 20,000 feet of 4-inch pipeline, 62,200 feet of 3-inch pipeline, 850 feet of 2-inch pipeline, and a 50 BHP Compressor Station, together with all appurtenant facilities.

The applicant shows that the Millersburg Division is far removed from Ohio Gas principal operating area at Bryan, Ohio; furthermore, the Millersburg and Bryan Divisions are not interconnected and the distance factor has caused problems in supervision and administration. Ohio Gas, therefore, desires to sell the subject facilities. None of Applicant's facilities presently being used to serve Ohio Gas will be abandoned. Such facilities, together with those proposed to be acquired, will be used by Applicant in the distribution of natural gas at retail in the Millersburg area.

Applicant will acquire the Millersburg Division at a price based on the depreciated original cost of the properties less contributions in aid of construction on the closing date. The estimated price for the properties as of December 31, 1960, is $409,035; of this amount an estimated $142,165 is attributable to jurisdictional facilities.

Applicant states that it will operate the subject facilities without interruption of service to existing consumers.

The Public Utilities Commission of Ohio has approved the proposed acquisition of facilities.

Pursuant to due notice, a public hearing was held in Washington, D.C., on April 30, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, The Ohio Fuel Gas Company, an Ohio corporation having its principal place of business in Columbus, Ohio, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of August 21, 1945, in Docket No. G–371 (4 FPC 1033).

(2) The facilities proposed to be acquired and operated by Applicant, as hereinbefore described and as more fully described in the application, as supplemented, in this proceeding, will be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the acquisition and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) The transportation of natural gas by means of facilities to be acquired by Applicant from Ohio Gas, as more fully described in the application, as supplemented, in this proceeding, will be made in interstate commerce, subject to the jurisdiction of the Commission, and such transportation is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The acquisition and operation of the facilities and the related transportation of natural gas, as proposed by Applicant, are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) The natural gas service to be abandoned, as heretofore described and as more fully described in the application, as supplemented, in this proceeding, is subject to the jurisdiction of the Commission, and abandonment of such

natural gas service is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(6) Such abandonment by Applicant, as heretofore described, is permitted by the public convenience and necessity, and an order authorizing and approving same should be issued as hereinafter ordered.

(7) Applicant is able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(8) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (d), and (e) of Section 157.20 of such Regulations.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing The Ohio Fuel Gas Company to acquire and operate the facilities and to transport natural gas as hereinbefore described, all as more fully described in the application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (d) and (e) of Section 157.20 of such Regulations.

(C) The acquisition hereinabove authorized shall be consummated and operation begun by Applicant within 6 months of the date hereof.

(D) Permission for and approval of the abandonment by Applicant of natural gas service to Ohio Gas hereinbefore described, all as more fully described in the application, as supplemented, in this proceeding, be and the same is hereby granted.

(E) Applicant shall advise the Commission of the date of the abandonment within 10 days of the date thereof.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

SOUTHERN NATURAL GAS COMPANY, DOCKET NO. CP62-198

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 14, 1962)

On February 21, 1962 Southern Natural Gas Company (Applicant) filed in Docket No. CP62-198 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the 12-month period commencing

August 7, 1962, at a total cost not to exceed $3,000,000, with no single project to exceed a cost of $500,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its existing pipeline system new supplies of natural gas which will be purchased from producers thereof in various areas generally coextensive with said system.

Applicant will finance the subject facilities from cash on hand or cash which will be available from current operations.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 3, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Southern Natural Gas Company, a Delaware corporation having its principal place of business in Birmingham, Alabama, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 6, 1942, in Docket No. G–296 (3 FPC 822).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction of the facilities during a 12-month period and the operation thereof, as proposed by Applicant, to take natural gas purchased from producers thereof are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(6) The authorization hereinafter granted should be limited to construction during the 12-month period commencing August 7, 1962, and the total expenditures for facilities to be constructed hereunder should be limited to a maximum of $3,000,000, with no single project to exceed a cost of $500,000.

(7) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before October 7, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the actual final costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record

and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Southern Natural Gas Company to construct during the 12-month period commencing August 7, 1962, the proposed facilities hereinbefore described, as more fully described in the application in this proceeding, and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Southern Natural Gas Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) The authorization granted in paragraph (A) above is hereby limited to construction during the 12-month period commencing August 7, 1962, and the total expenditures for facilities to be constructed hereunder are limited to a maximum of $3,000,000, with no single project to exceed a cost of $500,000.

(D) Applicant shall submit, on or before October 7, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the actual final costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

AMERICAN GAS COMPANY *v.* MICHIGAN WISCONSIN PIPE LINE COMPANY AND MILWAUKEE GAS LIGHT COMPANY, DOCKET NO. CP62-84

ORDER DISMISSING COMPLAINT

(Issued May 15, 1962)

On September 29, 1961, American Gas Company (American), an existing natural-gas utility with its principal place of business at 546 South 24th Avenue, Omaha 5, Nebraska, filed a "Complaint and Petition for Issuance of Declaratory Order and for Other Relief" in the above-entitled docket. In its complaint, American alleges that through its wholly-owned subsidiary, American Gas Company of Wisconsin, Inc., it has obtained natural gas distribution franchises in about 14 communities in north central Wisconsin and that it proposes to provide natural-gas service to these communities by obtaining from Midwestern Gas Transmission Company a supply of gas pursuant to Section 7(a) of the Natural Gas Act.[1]

[1] American filed an application on October 23, 1961, in Docket No. CP62-104 seeking an order from the Commission directing Midwestern Gas Transmission Company to sell and deliver the necessary gas for its project. This application has been scheduled for hearing to commence May 17, 1962.

American further alleges that it filed on August 29, 1961, an application with the Public Service Commission of Wisconsin for certificate authority to construct and operate the facilities necessary to render natural-gas service in these communities and that on the same day that American filed its application with the Wisconsin Commission, Milwaukee Gas Light Company (Milwaukee Gas) also filed an application with the Wisconsin Commission proposing service to six of the same communities proposed for service in American's application.

In view of the action to be taken in this order, it is unnecessary to recite herein the nature of American's complaint against Milwaukee Gas and Michigan Wisconsin Pipe Line Company (Michigan Wisconsin) other than to note that Michigan Wisconsin and Milwaukee Gas filed separate answers on November 6, 1961, denying that there was any basis for the allegations made in American's complaint.

Milwaukee Gas' answer also states that on October 20, 1961, Milwaukee Gas filed a motion with the Wisconsin Commission requesting permission to withdraw its application to serve the Wisconsin communities to which American had referred in its complaint, and that on October 25, 1961, the Wisconsin Commission had granted Milwaukee Gas' motion to withdraw its application. On page 13 of its answer, Michigan Wisconsin states: "This action may have the effect of rendering moot American's complaint to this Commission".

The Commission finds:

Since American Gas Company's complaint against Milwaukee Gas Light Company and Michigan Wisconsin Pipe Line Company was based upon the filing by Milwaukee Gas of an application to render service in some of the same communities proposed for service by American, American Gas Company's complaint has been rendered moot by Milwaukee Gas' withdrawal of its application filed with the Public Service Commission of Wisconsin, as hereinbefore described.

The Commission orders:

The complaint filed on September 29, 1961, by American Gas Company in Docket No. CP62–84 is hereby dismissed.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

AREA RATE PROCEEDING, DOCKET NO. AR61–2; ALADDIN EXPLORATION COMPANY, INC., ET AL., DOCKET NO. CI61–1564, ET AL.; AMERADA PETROLEUM CORPORATION, ET AL., DOCKET NO. RI60–18, ET AL.

ORDER ADDING RESPONDENTS AND CONSOLIDATING PROCEEDINGS

(Issued May 15, 1962)*

On May 10, 1961, the Commission issued an order "Instituting Rate Proceeding for the Southern Louisiana Area, Consolidating Proceedings and Prescribing Preliminary Procedure" which, among other things, instituted a proceeding to establish just and reasonable rate or rates for the sales of natural gas produced in the Southern Louisiana area as defined in the order and making respondents in the proceeding all persons named in Appendix "A" thereto and all parties on

*Published in the Federal Register on May 22, 1962 (27 F.R. 4820).

whose behalf such persons had filed FPC gas rate schedules for sales in such area, and consolidating therein a number of certificate proceedings listed in Appendix "B" thereto, as well as a number of rate suspension proceedings listed in Appendix "C" thereto. The said order was published in the Federal Register on May 17, 1961 (26 F.R. 4296) (25 FPC 942). By subsequent orders certain dockets were severed from and others were consolidated with the Docket No. AR61–2 proceedings.

Attached hereto as appendices are: (1) Appendix "A" (Supplement), a listing of additional persons having rate schedules on file for sales in the area who were not heretofore made respondents in the proceedings; (2) Appendix "B" (Supplement), a listing of additional proceedings on applications for certificates of public convenience and necessity which have not heretofore been consolidated with the said proceedings; and (3) Appendix "C" (Supplement), a listing of additional rate suspension proceedings which have likewise not heretofore been consolidated with the said proceedings. Since the persons and proceedings listed in said appendices are concerned with the sale of gas produced in the Southern Louisiana area, we have decided that these persons should be added as respondents and the listed proceedings should be consolidated for hearing with the Docket No. AR61–2 proceedings.

The Commission finds:

Good cause exists to join as respondents the persons listed in Appendix "A" (Supplement) hereto and all parties on whose behalf such persons have filed FPC gas rate schedules for sales in the Southern Louisiana area and to consolidate for the purpose of hearing all of the proceedings designated in Appendices "B" (Supplement) and "C" (Supplement) hereto with the Docket No. AR61–2 proceedings,

Pursuant to the provisions of the Natural Gas Act, particularly Sections 4, 5, 7, 10, 14, 15 and 16 thereof,

The Commission orders:

(A) The persons listed in Appendix "A" (Supplement) and all parties on whose behalf such persons have filed FPC gas rate schedules for sales in the Southern Louisiana area be and they are hereby made respondents in the proceedings in Docket Nos. AR61–2, *et al.*

(B) The pending proceedings designated in Appendices "B" (Supplement) and "C" (Supplement) be and they are hereby consolidated for the purposes of hearing with the proceedings in Docket Nos. AR61–2, *et al.*

(C) A copy of this order will be served upon each of the Respondents set out in Appendix "A" (Supplement).

APPENDIX "A" (Supplement)

Respondents[1]

Benin Oil Company
Brunner, Arnold H. & Company
Cockrell, E., Jr.
Dorn & Miller Company
Freedom Minerals, Inc.
Grigsby, Jack W.
Hibbert, R. E.
Hunt, Hassie Trust
Hunt, Lamar
Lamson & Bennett, Inc.
Lyons, C. H., Sr.
McCain, M. F.
Midhurst Oil Corporation
Peltier, Harvey

[1] All persons named herein and all parties on whose behalf such persons have filed FPC Gas Rate Schedules for sales in Southern Louisiana are joined as respondents in these proceedings.

APPENDIX "A" (Supplement)—Continued

Respondents[1]—Continued

The Preston Oil Company
Richardson & Bass, Louisiana Account
Riverside Oil Company
Skelly Oil Company
Southwest Gas Producing Company, Inc.
State Exploration Company
Texas Liberty Gas Corporation
Tex-Star Oil and Gas Corporation
The Texstar Corporation[2]
The TXL Oil Corporation
Union Texas Petroleum, a Division of Allied Chemical Corporation[3]
W. E. Walker
Cordell, J. H.

[1] See footnote on p. 953.
[2] Successor to Petroleum Leaseholds Inc.
[3] Successor to Union Texas Natural Gas Corporation.

APPENDIX "B" (Supplement)

Producer[1]	*Docket No.*
Amerada Petroleum Corporation	CI62-216, CI62-525, CI62-805
Atlantic Refining Company	CI62-8, CI62-146, CI62-416, CI62-435
Austral Oil Company, Inc. (Operator), et al	CI62-395
Bel Oil Corporation	CI61-1799
Bruner, Arnold H. & Company[2]	CI62-305
The California Co., A Division of California Oil Company	CI62-145, CI62-231
Cities Service Production Company	CI62-135
E. Cockrell, Jr	CI62-400
Continental Oil Company	CI62-147
Cordell, J. H	CI62-614
Dorn & Miller Company	CI62-897
Falcon Seaboard Drilling Company	CI62-1225
Forest Oil Corporation	CI62-283
Freeport Oil Company	CI62-720
Gulf Oil Corporation	CI61-1630, CI62-411, CI62-412, CI62-859, CI62-62
R. E. Hibbert	CI62-702
Hudson Gas & Oil Corporation	CI62-841
Humble Oil and Refining Company	CI62-69
Jameson, F. E., et al	CI62-546
Kerr-McGee Oil Industries, Inc	CI62-398
Lamson & Bennett, Inc., et al	CI62-606
M. F. McCain, et al	CI62-582
George C. McGhee, Oper., et al	CI61-1737
Mosbacher, Robert	CI62-693
Newmont Oil Company	G-17765
North Central Oil Corporation	CI62-313
Ocean Drilling and Exploration Company	CI61-1708
Owen, J. P	CI62-538
Pan American Petroleum Corporation	CI62-724, CI62-782
O'Meara, Robert W	CI62-479
The Preston Oil Company	CI62-1209
The Pure Oil Company	CI62-1224
Samadam Oil Corporation	CI62-378, CI62-561

See footnotes at end of table.

Shell Oil Company	CI62-623, CI62-625
Shoreline Exploration, Inc	CI62-102
Socony Mobile Oil Company, Inc	CI61-659[3], CI61-1640
Sohio Petroleum Company	CI62-337
Southdown, Inc	CI62-550, CI62-551
State Exploration Company	CI62-326
Tennessee Louisiana Oil Company	CI62-682[3]
Texaco Inc	CI61-1713, CI62-16, CI62-407, CI62-544
Texas Gas Exploration Corporation	CI62-930
Tidewater Oil Company	CI62-137, CI62-638
J. C. Trahan Drilling Contractors, Incorporated	CI62-771
Union Oil Company of California	CI62-806, CI62-822
Union Oil and Gas Corporation of Louisiana	G-13221[4]
Whitehall Oil Company, Inc., et al	CI61-1809
Texstar Corporation[5]	CI62-951

*Producers listed herein are the party applicants and such listing does not necessarily include all parties covered by the certificate application involved.

[1] Texas Liberty Gas Corporation has filed in Docket No. CI62-683 to be substituted as Applicant in Docket No. CI62-305.

[2] Socony Mobil Oil Company, Inc. has been substituted for Republic Natural Gas Company in CI61-659.

[3] Tenneco Oil Company has filed a motion to be substituted for Tennessee Louisiana Oil Company in this proceeding.

[4] Union Texas Petroleum, a Division of Allied Chemical Corporation, has filed in Docket No. CI62-1010 as successor to Union Oil and Gas Corporation of Louisiana in this proceeding.

[5] Successor to Petroleum Leaseholds, Inc.

APPENDIX "C" (Supplement)

Producer[1]	*Docket No.*
Amerada Petroleum Corporation	G-17538, G-17539, RI62-222, RI62-282, RI62-288, RI62-289.
Atlantic Refining Company	RI62-77*, RI62-78*, RI62-276
Austral Oil Company, Inc. (Oper.), et al	RI62-93
Austral Oil Co., Inc. (Oper.), Agent for Oil Participations Inc.	RI62-94, RI62-360
Bel Oil Corporation	RI62-177, RI62-182
The British-American Oil Producing Company	G-17665, RI61-540, RI62-184*, RI62-274.
Benedum Trees Oil Company	RI62-191
Berkshire Oil Company	RI62-266
Brown, George R	RI62-145
Cabot Corporation	RI62-208*, RI62-133
The California Co., A Division of California Oil Company.	RI62-232, RI62-146, RI62-248.
Cities Service Production Company	RI62-58
Cities Service Petroleum Company	RI62-245
Columbian Carbon Company	RI62-79
Dixon Management Corporation	RI61-552
Falcon Seaboard Drilling Company	RI62-509
Forest Oil Corporation	RI62-68, RI62-69*

See footnotes at end of table.

APPENDIX "C" (Supplement)—Continued

Producer[1]	Docket No.
The F.O. Corp	RI62–214
General Crude Oil Company	RI61–548, RI62–359
Graridge Corporation	RI62–169
Gulf Oil Corporation	RI62–203, RI62–202, RI62–85, RI62–120
Mrs. Louise H. Herrington	RI62–270
Humble Oil and Refining Company	RI61–514 RI62–62, RI62–83, RI61–133, RI62–287
Hunt, H. L	RI62–228
Hassie Hunt Trust	RI62–227
Kerr-McGee Oil Industries, Inc	RI61–514, RI62–62, RI62–237, RI62–378
Mecom, John W	RI62–311
Midwest Oil Corporation	RI62–119
Midhurst Oil Corp	RI62–348
Owen, J. P	RI62–234
Pan American Petroleum Corporation	RI62–220, RI62–98,* RI62–99, RI62–356
Placid Oil Company	RI62–211, RI62–257
Secure Trusts	RI62–226
Shoreline Exploration, Incorporated	RI62–103, RI61–557
Sinclair Oil and Gas Company	RI62–190
Socony Mobil Oil Co., Incorporated	RI62–153, RI62–112*
Sohio Petroleum Company	RI62–89, RI62–269, RI62–320
Southwest Gas Producing Company, Inc	RI62–230, RI62–241
Sun Oil Company	RI62–101*
Sunray Mid-Continent Oil Company[2]	RI62–32,* RI61–463
The Superior Oil Company	G–17707, RI62–278
Texaco, Inc	RI62–155, RI62–156, RI62–157
Texas Gulf Producing Company	RI62–75, RI62–90
Tex-Star Oil and Gas Corporation	RI62–358
Tidewater Oil Company	RI62–109,* RI62–149
Union Oil Company of California	RI62–43, G–17705, RI62–295
Union Texas Natural Gas Corporation[3]	RI62–91

*This proceeding is consolidated only insofar as it pertains to sales in South Louisiana.

[1] This producer designation is for general identification and may not include all of the respondents designated in the respective orders initiating rate suspension proceedings.

[2] Now Sunray DX Oil Company.

[3] Now Union Texas Petroleum, a Division of Allied Chemical Corporation.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

SOCONY MOBIL OIL COMPANY, INC. (SUCCESSOR TO MAGNOLIA PETROLEUM COMPANY), DOCKET NO. G–11742, ET AL., AND G–19516

ORDER AMENDING OUTSTANDING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY TO REFLECT CHANGE IN HOLDER, AND CANCELLING DOCKET NUMBER

(Issued May 15, 1962)

On September 21, 1959, Socony Mobil Oil Company, Inc. (Socony), joined by Magnolia Petroleum Company (Magnolia), filed in Docket No. G–19516 an ap-

plication for authorization to continue certain services previously authorized to Magnolia in the docket numbers listed, with their related certificate order designations, in APPENDIX I which is attached hereto and made a part hereof.

Such action was prompted by merger, effective September 30, 1959, between Socony and Magnolia (Socony's wholly-owned subsidiary) whereby Socony acquired all rights, privileges, obligations, etc., previously held by Magnolia.

Subsequent to the filing of the aforesaid application, Socony filed twenty-eight motions to amend, revising certain services originally authorized to Magnolia and now to be continued by Socony, all as reflected in APPENDIX II which is also attached hereto and made a part hereof. These amendments require considerations not encompassed in this order.

The Commission finds:

(1) It is in the public interest and appropriate in carrying out the provisions of the Natural Gas Act to amend the respective orders issuing certificates of public convenience and necessity to Magnolia in the docket numbers listed in APPENDIX I attached hereto to reflect Socony as the certificate holder in each case.

(2) The twenty-eight motions to amend Socony's application in Docket No. G–19516, reflected in APPENDIX II attached hereto, should be construed as petitions to amend the authorizations in the related original dockets and no action on the disposition of these petitions to amend should be taken in this order.

(3) The docket designation of Docket No. G–19516, previously assigned to Socony's application to continue the services heretofore authorized to Magnolia, should be cancelled.

The Commission orders:

(A) The outstanding certificates of public convenience and necessity heretofore granted to Magnolia by orders of the Commission listed in APPENDIX I attached hereto and made a part of this order, be and the same are hereby amended by substituting Socony Mobil Oil Company, Inc. for Magnolia Petroleum Company as holder thereof.

(B) In all other respects, said certificate authorizations shall remain in full force and effect as issued.

(C) The twenty-eight motions to amend Socony's application in Docket No. G–19516 are hereby construed as petitions to amend the related original docket authorizations as reflected in APPENDIX II attached hereto and made a part hereof, and no action on said petitions is taken herein.

(D) The docket designation of Docket No. G–19516 assigned to Socony's subject application is hereby cancelled.

APPENDIX I

Certificate of public convenience and necessity have been issued to Magnolia Petroleum Company, Magnolia Petroleum Company, Operator, or Magnolia Petroleum Company (Operator), *et al.* in the following dockets by the below-identified orders:

Docket Nos. G–11742, G–11863, G–11864, G–11866 through G–11869, G–11893, G–11894, G–11918, G–11931 through G–11933, G–11935 through G–11952, G–11954, G–11957 through G–11961, G–11989, G–11995 through G–11997, G–12000 through G–12006, G–12070 through G–12074, G–12079, G–12080, G–12082 through G–12084, G–12086, G–12087, G–12089, G–12090, G–12092, G–12098, G–12103 and G–12431. (*In the Matters of Magnolia Petroleum Company*, Docket Nos. G–11742, *et al.*, issued September 9, 1958.)

Docket Nos. G–11860 through G–11862, G–11870, G–11912, G–11913, G–11915, G–11934, G–11953, G–11955, G–11956, G–11985 through G–11987, G–11998, G–11999, G–12081, G–12085, G–12088, G–12091, G–12093, G–12096, G–12097, G–12100 through G–12102, G–12584 through G–12594, and G–12654 through G–12656. (*In the Matters of Magnolia Petroleum Company, et al.*, Docket Nos. G–11860, *et al.*, issued June 19, 1958.)

Docket Nos. G–11911 and G–12078. *In the Matters of Lone Star Producing Company, et al.*, Docket Nos. G–10420, *et al.*, issued April 25, 1957.)

Docket Nos. G–11917, G–11984, G–12323, G–12686 and G–12718. (*In the Matters of Toklan Oil Corporation, et al.*, Docket Nos. G–10533, *et al.*, issued November 4, 1957.)

Docket Nos. G–11911 and G–12078. (*In the Matters of Lone Star Producing*

Docket No. G–12728. (*In the Matters of Arkansas Fuel Oil Corporation, et al.*, Docket Nos. G–9692, *et al.*, issued November 26, 1957.)

Docket Nos. G–12095, G–12364 and G–12904. (*In the Matters of Magnolia Petroleum Company, et al.*, Docket Nos. G–12095, *et al.*, issued April 25, 1958.)

Docket No. G–13324. (*In the Matters of Ashland Oil & Refining Co., et al.*, Docket Nos. G–12796, *et al.*, issued April 24, 1958.)

Docket No. G–13943. (*In the Matters of Cyprus Oil Company, Operator, et al.*, Docket Nos. G–13870, *et al.*, issued April 17, 1958.)

Docket No. G–12099. (*In the Matters of Sabianna Oil Company, Inc., et al.*, Docket Nos. G–12057, *et al.*, issued October 8, 1957.)

Docket No. G–12362. (*In the Matters of Southern Natural Gas Company, et al.*, Docket Nos. G–11234, *et al.*, issued July 12, 1957.)

Docket Nos. G–12614, G–12820 and G–12840. (*In the Matters of The Ohio Oil Company, et al.*, Docket Nos. G–12578, *et al.*, issued June 2, 1958.)

Docket No. G–12657. (*In the Matters of Texas Eastern Transmission Corporation, et al.*, Docket Nos. G–11784, *et al.*, issued April 24, 1958.)

Docket No. G–12770. (*In the Matters of Oklahoma Natural Gas Company, et al.*, Docket Nos. G–12759, *et al.*, issued September 3, 1958.)

Docket No. G–12821. (*In the Matters of Northern Natural Gas Company, et al.*, Docket Nos. G–13041, *et al.*, issued December 13, 1957.)

Docket No. G–12861. (*In the Matters of Arkansas Fuel Oil Corporation, et al.*, Docket Nos. G–3031, *et al.*, issued February 10, 1958).

Docket No. G–12903. (*In the Matters of Magnolia Petroleum Company, et al.*, Docket Nos. G–12903, *et al.*, issued December 4, 1958.)

Docket Nos. G–14908, G–14913 and G–14914. (*In the Matters of L. B. Porter, et al.*, Docket Nos. G–14893, *et al.*, issued December 18, 1958.)

Docket No. G–13275. (*In the Matters of The Atlantic Refining Company, et al.*, Docket Nos. G–13257, *et al.*, issued October 27, 1958.)

Docket No. G–13826. (*In the Matters of Petroleum, Inc., et al.*, Docket Nos. G–12824, *et al.*, issued October 27, 1958.)

Docket No. G–13543. (*In the Matters of Magnolia Petroleum Company, et al.*, Docket Nos. G–13543, *et al.*, issued March 25, 1958.)

Docket No. G–14246. (*In the Matters of Tensas Gas Gathering Corporation, et al.*, Docket Nos. G–13588, *et al.*, issued March 31, 1958.)

Docket Nos. G–13746 and G–13780. (*In the Matters of Transcontinental Gas Pipe Line Corporation, et al.*, Docket Nos. G–13169, *et al.*, issued September 4, 1958.

Docket Nos. G–14223 and G–14225. (*In the Matters of Cities Service Oil Company, et al.*, Docket Nos. G–14175, *et al.*, issued August 12, 1959.)

Docket No. G–14959. (*In the Matters of Magnolia Petroleum Company, et al.*, Docket Nos. G–14959, *et al.*, issued July 27, 1959).

Docket No. G–15017. (*In the Matters of La Gloria Oil and Gas Company, et al.*, Docket Nos. G–14996, *et al.*, issued April 8, 1959.)

Docket Nos. G–15182 and G–15183. (*In the Matters of A. J. Hodges Industries, Inc., et al.*, Docket Nos. G–15151, *et al.*, issued March 6, 1959.)

Docket No. G–15241. (*In the Matters of United States Smelting Refining and Mining Company, et al.*, Docket Nos. G–14891, *et al.*, issued January 2, 1959.)

Docket No. G–15270. (*In the Matters of Mound Company, et al.*, Docket Nos. G–15114, *et al.*, issued May 1, 1959.)

Docket No. G–16379. (*In the Matters of Skelly Oil Company, et al.*, Docket Nos. G–15463, *et al.*, issued June 19, 1959.)

Docket No. G–17041. (*In the Matters of Texas Gas Transmission Corporation, et al.*, Docket Nos. G–17335, *et al.*, issued August 10, 1959.) (Opinion No. 327)

Docket No. G–13216. (*In the Matters of Keener Oil Company, et al.*, Docket Nos. G–12575, *et al.*, issued June 26, 1959.)

APPENDIX II

Amendment No.	Date filed	Effect of revision instrument	Date of instrument	Original authorization
1	11-16-59	Adds acreage	4- 8-59	G-14223
2	11-20-59	Deletes acreage	8-26-59	G-13826
3	2-26-60	Deletes acreage	11-27-59	G-13826
4	2-26-60	Deletes acreage	11-20-59	G-12718
5	5- 9-60	Deletes acreage	3-21-60	G-11957
6	7-18-60	Adds acreage	6-14-60	G-11950
7	7-22-60	Adds acreage	7- 8-60	G-11947
8	7-22-60	Adds acreage	5-26-60	G-13324
9	7-22-60	Adds acreage	5-26-60	G-12840
10	8- 5-60	Adds acreage	7- 1-60	G-16379
11	8-19-60	Adds acreage	5-26-60	G-11893
12	9-21-60	Adds acreage	8-15-60	G-12728
13	11- 7-60	Deletes acreage	10- 4-60	G-13826
14	12- 9-60	Deletes acreage	10-12-60	G-13826
15	12- 9-60	Deletes acreage	1-26-54	G-12003
16	1-24-61	Adds acreage	12-14-60	G-11931
17	2- 3-61	Adds acreage	1- 5-60	G-11862
18	2-14-61	Adds acreage	12- 9-60	G-13324
19	2-20-61	Designates applicant as unit operator	------	G-12004
20	3-21-61	Deletes acreage	10-13-60	G-13746
21	3-21-61	Deletes acreage	10-13-60	G-13746
22	3-21-61	Deletes acreage	12- 8-60	G-13826
23	3-29-61	Adds acreage	2- 1-61	G-16379
24	4- 6-61	Adds acreage	2-24-61	G-13324
25	6-30-61	Adds acreage	5- 1-61	G-11957
26	11- 3-61	Adds acreage	8-28-61	G-13826
27	2-12-62	Deletes acreage	11- 6-61	G-11957
28	2-12-62	Deletes acreage	12-21-55 1-20-56 1- 7-58	G-11957

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr. and Harold C. Woodward.

SOUTHWESTERN PUBLIC SERVICE COMPANY, DOCKET NO. E-7038

ORDER INSTITUTING INVESTIGATION, PROVIDING FOR HEARING AND SUSPENDING PROPOSED RATE SCHEDULE CHANGES

(Issued May 15, 1962)

Data currently available to this Commission indicate the need for a formal investigation concerning the lawfulness of all rate schedules filed pursuant to Section 205 of the Federal Power Act by Southwestern Public Service Company

(Southwestern), Amarillo, Texas. At present 22 rate schedules of that Company are on file with this Commission for wholesale electric service which the Company renders to three investor-owned utility resale customers and 17 rural electric cooperative resale customers. Twelve rate schedules were proffered for filing by Southwestern on March 28, 1962 to supersede existing rate schedules for service to twelve of its rural electric cooperative customers. Unless suspended by order of the Commission, as hereinafter provided, the latter rate schedules would become effective May 19, 1962.

The foregoing schedules including the proposed rate schedule changes are designated in the files of the Commission as follows:

Customer	Designation of currently effective rate schedules	Designation of proposed changed rate schedules
New Mexico Electric Service Co. Hobbs, New Mexico.	FPC No. 14, Supplement No. 1.	
Cochran Power & Light Co. Morton, Texas.	FPC No. 15, Supplement Nos. 1 & 2; FPC No. 34.	
Lea County Electric Cooperative, Inc. Lovington, New Mexico.	FPC No. 16; FPC No. 35; Supplement No. 1.	
Community Public Service Co. Fort Worth, Texas.	FPC No. 17, Supplement No. 1.	
Bailey County Electric Cooperative, Inc., Muleshoe, Texas.	FPC No. 18	FPC No. 36.
Swisher County Electric Cooperative, Inc., Tulia, Texas.	FPC No. 19, Supplement No. 1.	FPC No. 47, Supplement No. 1.[1]
Central Valley Electric Cooperative, Artesia, New Mexico.	FPC No. 20	FPC No. 37.
Tri-County Electric Cooperative, Inc., Hooker, Oklahoma.	FPC No. 21	
South Plains Electric Cooperative, Inc., Lubbock, Texas.	FPC No. 22, Supplement No. 1.	FPC No. 46.
Roosevelt County Electric Cooperative, Inc., Portales, New Mexico.	FPC No. 23	FPC No. 45.
Rita Blanca Electric Cooperative, Inc., Dalhart, Texas.	FPC No. 24	
North Plains Electric Cooperative, Inc., Perryton, Texas.	FPC No. 25	
North Fork Electric Cooperative, Inc., Sayre, Oklahoma.	FPC No. 26	FPC No. 44.
Lyntegar Electric Cooperative, Inc., Tahoka, Texas.	FPC No. 27	FPC No. 43.
Lighthouse Electric Cooperative, Inc., Floydada, Texas.	FPC No. 28, Supplement No. 1.	FPC No. 40, Supplement No. 1.[2]
Lamb County Electric Cooperative, Inc., Littlefield, Texas.	FPC No. 29, Supplement No. 1.	FPC No. 42.
Greenbelt Electric Cooperative, Inc., Wellington, Texas.	FPC No. 30	FPC No. 41.
Farmers Electric Cooperative, Inc. of New Mexico, Clovis, New Mexico.	FPC No. 31	FPC No. 39.
Deaf Smith County Electric Cooperative, Inc., Hereford, Texas.	FPC No. 32	FPC No. 38.
Pioneer Cooperative Association, Inc., Inc., Ulysses, Kansas.[3]	FPC No. 33	

[1] Supplement No. 1 to FPC No. 47 is a redesignation of an existing rate schedule providing for facility construction and wheeling arrangements. (Supplement No. 1 to FPC No. 19).

[2] Supplement No. 1 to FPC No. 40 embodies an agreement dated December 12, 1961 covering operational practices and facility payments by Southwestern to Lighthouse which Southwestern appears to regard as related to its power supply agreement with Lighthouse dated November 27, 1961, designated as Rate Schedule FPC No. 40. The two agreements were submitted for filing concurrently.

[3] With the exception of Rate Schedule FPC No. 33, all of Southwestern's effective and proposed rate schedules embody written contractual agreements between Company and the respective customers and provide for all requirements electric service or supplemental electric service. Rate Schedule FPC No. 33 provides for the rendition of emergency service only.

Southwestern's Rate Schedule FPC No. 14 and Supplement No. 1 (New Mexico Electric) Nos. 15 and Supplements 1 and 2, 34 (Cochran Power) and No. 17 and Supplement No. 1 (Community Public Service) provide for the following rates and charges:

FPC No. 14, Supplement No. 1—*demand charge* $1.50/kw demand/mo. (first 12,000 kw) and $1.15/kw demand/mo. (above 12,000 kw); *energy charge* .55¢ /kwh for first 360 kwh/kw demand/mo. and .425¢/kwh for all additional kwh/mo.; fuel adjustment clause based upon approximately 20,000 BTU/kwh.

FPC No. 15, Supplement Nos. 1 and 2—*demand charge* $2.20/mo./kw of computed demand; *energy charge* .5¢/kwh; minimum charge clause; and power factor clause.

FPC No. 34—*demand charge* $370 for first 200 kw, or less demand/mo. and $1.25/kw demand/mo. above 200 kw; *energy charge* .75¢/kwh for first 300 kwh used/mo./kw demand or first 120,000 kwh used/mo. whichever is greater, and .50¢/kwh for all additional kwh/mo.; ratchet and minimum charge clauses; power factor clause; primary service discount; and fuel adjustment clause based upon approximately 20,000 BTU/kwh.

FPC No. 17, Supplement No. 1—*demand charge* $370 for first 200 kw, or less, demand/mo., $1.25/kw demand/mo. for next 1800 kw, and $1.15/kw demand/mo. thereafter; *energy charge* .75¢/kwh for first 200 kwh used/mo./kw demand or first 80,000 kwh used/mo. whichever is greater, and .50¢/kwh for all additional kwh/mo.; ratchet and minimum charge clauses; power factor clause; primary service discount; facility payment; and fuel adjustment clause based upon approximately 20,000 BTU/kwh.

Southwestern's Rate Schedule FPC Nos. 16, 35 and Supplement No. 1 (Lea County Electric Cooperative) and No. 33 (Pioneer Cooperative) provide for the following rates and charges:

FPC No. 16—*demand charge* $2.00/mo./kw demand; energy charge none first 125 kwh/kw of demand, 1.25¢/kwh next 125 kwh/kw of demand, and .8¢/kwh for excess over 250 kwh/wh of demand; ratchet and minimum charge clauses; power factor clause; prompt payment discount; and fuel adjustment clause based upon 25,000 BTU/kwh, based on generation at a single plant.

FPC No. 35, Supplement No. 1—*demand charge* $1.725/kw demand/mo. including 100 kwh/kw demand; *energy charge* .46¢/kwh for all kwh/mo. in excess of 100 kwh/kw demand; ratchet and minimum demand clauses; and fuel adjustment clause based upon approximately 15,000 BTU/kwh. The demand charge is not applicable during months of January, February, March, October, November and December.

FPC No. 33—*energy charge* 1¢/kwh for all kwh used/mo.; fuel adjustment clause based upon approximately 20,000 BTU/kwh.

Southwestern's Rate Schedule FPC Nos. 18, 19 and Supplement No. 1, 20, 21, 22 and Supplement No. 1, 23, 24, 25, 26, 27, 28 and Supplement No. 1, 29 and Supplement No. 1, 30, 31 and 32, for service to the other rural electric cooperatives, as above-named, provide for the following rates and charges: *demand charge* $1.725/kw demand/mo. including 100 kwh/kw demand; *energy charge* .46¢/kwh for all kwh/mo. in excess of 100 kwh/kw demand; and fuel adjustment clause based upon approximately 15,000 BTU/kwh. The demand charge is not applicable during the months of January, February, March, October, November and December.

Southwestern's proffered rate schedule changes, as designated above, would decrease Company's present rates to the twelve Cooperatives concerned by approximately $79,639 (2.08%) per annum for the twelve customers based upon estimated 1962 deliveries of power and energy. For the twelve-month period ending December 31, 1962, Southwestern's revenues from those customers under present rate schedules are estimated to total $3,820,507. Based upon the same estimated deliveries, Southwestern's operating revenues under the proposed rates would be $3,740,868. The reduction would be accomplished through elimination of fuel adjustment clauses, establishment of a maximum annual average bill of 7.5 mills per kwh; and an increase of .4 mill per kwh in Company's present energy charge.

Review and analysis of available office data indicate that certain of Southwestern's Rate Schedule FPC Nos. 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25,

26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46 and 47, as supplemented and more fully described above, may result in excessive rates or charges; certain of them may place an undue burden upon other of Southwestern's electric utility customers; and some or all of those schedules may be unduly discriminatory, unduly preferential, or otherwise unjust, unreasonable and unlawful within the meaning of the Federal Power Act. Additional factual data necessary for a resolution of those questions must be obtained. Accordingly, it is necessary and appropriate for the purposes of the Federal Power Act, particularly Sections 205, 206, 304, 307, 308 and 309 thereof, that the Commission enter upon a hearing and investigation concerning the lawfulness of all of Southwestern's rate schedules as supplemented and proposed to be changed as described above; that the operation or effectiveness of Southwestern's Rate Schedule FPC Nos. 36, 37, 38, 39, 40 and Supplement No. 1 thereto, 41, 42, 43, 44, 45, 46, and 47 be suspended and the use thereof deferred; and that Southwestern be directed to submit cost and revenue data all in the manner as hereinafter provided.

The Commission orders:

(A) A public hearing be held concerning the lawfulness of Southwestern's Rate Schedule FPC Nos. 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28. 29, 30, 31, 32, 33, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 45, 46, 47, and Supplements thereto, all as described above, at a time and place to be specified by notice of the Secretary.

(B) Pending that hearing and decision of the Commission the operation under the Federal Power Act of Southwestern's Rate Schedule FPC Nos. 36, 37, 38, 39, 40 and Supplement No. 1 thereto, 41, 42, 43, 44, 45, 46, and 47 is hereby suspended and the use of those schedules deferred until October 19, 1962. On that date those rate schedules shall take effect in the manner prescribed by the Federal Power Act, subject to further order of the Commission, unless this proceeding has been disposed of at a date previous thereto. During the period of suspension Southwestern's Rate Schedule FPC Nos. 18, 19, 20, 22 and Supplement No. 1 thereto, 23, 26, 27, 28 and Supplement No. 1 thereto, 29 and Supplement No. 1 thereto, 30, 31, 32 and Supplement No. 1 to 47, all as now on file with this Commission, shall remain and continue in effect. Unless otherwise ordered by the Commission, Southwestern shall not change the terms or provisions of any rate schedules specified in this paragraph until this proceeding has been disposed of or until the period of suspension has expired.

(C) Southwestern shall file, on or before July 16, 1962, cost and revenue data showing Company's costs of rendering service to each wholesale for resale customer served under the Rate Schedules referred to in paragraph (A) above, calculated in accordance with applicable Commission rulings and utilizing, among other things, as the test period the calendar year 1961 showing both historical revenues and *pro forma* adjustments thereto due to the proposed reductions and due to prospective changes in Southwestern's boiler fuel costs under all new gas supply contracts which the company may have entered into during the past thirty-six month period, a prudent net investment rate base, and a fair rate of return thereon.

(D) The foregoing showing shall not preclude or limit any additional showing by Southwestern or others and shall be without prejudice to any future action taken by the Commission or its staff, or to any future position Southwestern or others may wish to take as to the significance of, or conclusions to be drawn from, the above factual showing.

(E) The foregoing showing shall be submitted in writing with sufficient copies to provide this Commission with six copies, to provide each State Commission

affected with a like number of copies and to provide one copy each to all other parties as may be granted intervention in this proceeding.

(F) Notices of intervention or petitions to intervene in this proceeding may be filed with the Commission on or before June 15, 1962 and in accordance with the Commission's Rules of Practice and Procedure (18 CFR 1.8 and 1.37).

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NO. CP62–190

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 15, 1962)

On February 12, 1962, Transcontinental Gas Pipe Line Corporation (Applicant) filed in Docket No. CP62–190 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof from time to time during the 12-month period commencing May 22, 1962, at a total cost not to exceed $1,500,000, with no single project to exceed a cost of $500,000, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various areas generally coextensive with said system.

Applicant will finance the subject facilities from cash on hand or short term bank loans.

Pursuant to due notice a public hearing was held in Washington, D.C., on May 1, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Transcontinental Gas Pipe Line Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 28, 1950, in Docket No. G–1277 (9 FPC 32).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas purchased from producers thereof as proposed by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(6) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, within 90 days from the end of the 12-month period for which authorization is hereinafter granted, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the actual final costs of said facilities, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(7) The authorization hereinafter granted should be limited to construction during the 12-month period commencing May 22, 1962, and the total expenditures for facilities to be constructed thereunder should be limited to $1,500,000, with no single project to exceed a cost of $500,000.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Transcontinental Gas Pipe Line Corporation to construct during the 12-month period commencing May 22, 1962, the proposed facilities hereinbefore described, as more fully described in the application in this proceeding, and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Transcontinental Gas Pipe Line Corporation.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) Applicant shall submit within 90 days from the end of the 12-month period for which authorization was granted in paragraph (A) above, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization hereinbefore granted, (d) the location of said project or projects, (e) the actual final costs of said facilities, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the 12-month period commencing May 22, 1962, and the total expenditures for facilities to be constructed thereunder are hereby limited to $1,500,000, with no single project to exceed a cost of $500,000.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross, and Harold C. Woodward.

SIERRA PACIFIC POWER COMPANY, DOCKET NO. E-7031

ORDER AUTHORIZING THE ISSUANCE OF PROMISSORY NOTES

(Issued May 16, 1962)

Sierra Pacific Power Company (Applicant), a corporation organized under the laws of the State of Maine and doing business in the States of California and Nevada, with its principal place of business at Reno, Nevada, filed an application on March 29, 1962, as amended on April 17, 1962, for an order or orders, pursuant to Section 204 of the Federal Power Act, authorizing the issuances, as separate and independent transactions, of the following securities: (1) Short-term Promissory Notes in the aggregate principal amount of not in excess of $5,000,000 outstanding at any one time, and (2) $5,000,000, principal amount of First Mortgage Bonds, due 1992. Applicant now requests that an order be issued authorizing the proposed issuance of Promissory Notes.

The proposed Promissory Notes, in the aggregate principal amount of $5,000,000, including the total amount of all Notes presently outstanding under Section 204(e) of the Act,* will be issued to evidence bank loans to Applicant, and will bear interest at a rate per annum not in excess of one-quarter of 1% over the prime rate in effect in New York City, at the time of the borrowing or the renewal or extension of the loans, for short-term commercial loans to depositors. Each Note will be dated as of the date of issuance and delivery thereof and will mature not later than September 30, 1962.

The application states that no underwriter's or finder's fee will be paid in connection with the proposed issuance of Notes, and that none of the proposed Notes will be resold to the general public. The Notes will be discharged from the proceeds of the $5,000,000, principal amount of First Mortgage Bonds, due 1992, which Applicant proposes to issue in June or July, 1962.

Applicant states that it will use the net proceeds from the issuance of the proposed Notes, pending the sale of the proposed issuance of First Mortgage Bonds, to reimburse Applicant for construction expenditures heretofore made and to finance, in part, Applicant's 1962 construction program, estimated to cost $11,659,900. Principal items of expenditure are, as follows: $2,898,000 for continuing installation of Unit No. 1 and $1,014,000 for gas turbines, at Applicant's Frank A. Tracy Station, 17 miles east of Reno; $1,170,100 for transmission lines and substations, including $340,000 for the Buckeye-Tahoe Valley 120 kv line (total cost estimated at $540,000, to be completed in 1963) and $344,600 for the 120 kv Brunswick-Minden line; $3,048,900 for improvements to power plants, transmission and distribution system, for distribution and transmission substations, and for extensions, meters, services and transformer needed to serve new customers; $2,016,000 for extensions and improvements to existing facilities, reservoirs and flumes of Applicant's water department; $386,100 for Applicant's gas department; and $1,064,400 for general plant.

Written notice of the application has been given to the California Public Utilities Commission and the Nevada Public Service Commission, and to the

*Applicant, on May 3, 1962, filed a Certificate of Notification under Section 204(e) of the Federal Power Act, for the issuance of an unsecured promissory note in the amount of $1,600,000, payable to the First National Bank of Nevada, dated April 24, 1962, due on July 23, 1962, interest at 4½% per annum.

Governor of each of those States. Notice of the application was also given by publication in the Federal Register on April 7, 1962 (27 F.R. 3362), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before the 24th day of April, 1962 with the Federal Power Commission, Washington 25, D.C. No protest or petition or request to be heard in opposition to the granting of the application has been received.

The Commission finds:

(1) Applicant, a corporation, is a public utility within the meaning of Section 204 of the Federal Power Act, subject to the jurisdiction of the Commission as heretofore described and set forth in the Commission's order issued May 2, 1961, *Sierra Pacific Power Company*, Docket No. E–6984 (25 FPC 904).

(2) The proposed issuance of Promissory Notes, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State Commission within the meaning of Section 204(f) of the Act; and the proposed issuance of Promissory Notes, as described above, is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance of Promissory Notes in the aggregate principal amount of $5,000,000, all as described above, will be in excess of 5% of the par value of the other securities of Applicant, and, therefore, will not be exempt by virtue of Section 204(e) of the Act from the requirements of Section 204(a) of the Act.

(5) The proposed issuance of Promissory Notes, described above, will be exempt from the competitive bidding requirements of Section 34.1a of the Commission's Regulations under the Federal Power Act by reason of paragraph 34.1a(a)(2) thereof.

(6) The proposed issuance of Promissory Notes, as hereinafter authorized will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility, and which will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purposes.

The Commission orders:

(A) The proposed issuance of Promissory Notes by the Applicant, in an aggregate principal amount of not to exceed $5,000,000, at any one time outstanding, upon the terms and conditions and for the purposes set forth in the application, is hereby authorized, subject to the provisions of this order.

(B) This authorization is expressly conditioned upon the final maturity of all Notes to be issued pursuant thereto being not later than September 30, 1962.

(C) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuations, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(D) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States in respect to any securities to which this order relates.

AMERICAN LOUISIANA PIPE LINE CO., DOCKET NO. G-2306; MICHIGAN WISCONSIN PIPE LINE CO., G-2327; AMERICAN LOUISIANA PIPE LINE CO., G-10396; PANHANDLE EASTERN PIPE LINE CO., G-11061; TRUNKLINE GAS CO., CP60-22 (PHASE TWO); PANHANDLE EASTERN PIPE LINE CO., CP60-40; PANHANDLE EASTERN PIPE LINE CO., CP60-60; PANHANDLE EASTERN PIPE LINE CO., CP61-36; CITIZENS GAS CO., CP61-54; CITY OF LACYGNE, KANSAS, CP61-69; CENTRAL ILLINOIS LIGHT CO., CP61-114; CENTRAL ILLINOIS LIGHT CO., CP61-115; PANHANDLE EASTERN PIPE LINE CO., CP61-136; ILLINOIS POWER CO., CP61-160; CITIZENS GAS CO., CP61-191; CITIZENS GAS CO., CP61-192

ORDER AFFIRMING INITIAL DECISION OF PRESIDING EXAMINER

(Issued May 17, 1962)*

Syllabus

1. Under facts and circumstance of this proceeding Commission *finds* 10-cent formula should apply to construction of laterals for service to North Central Public Service Co. and Wisconsin Power and Light Co., however such finding should not be construed as necessarily foreclosing Michigan Wisconsin from contesting application of formula in future proceedings. P. 969.
2. Commission *directs* Panhandle Eastern and Trunkline, under Section 7(a) of the Natural Gas Act, to establish and maintain physical connection of their transportation facilities with applicants' proposed facilities, and deliver and sell natural gas to applicants. P. 969; 983.
3. Commission *directs* Michigan Wisconsin, under Section 7(a) of the Natural Gas Act to extend its transportation facilities; establish and maintain connection of such facilities with applicants' proposed facilities, and deliver and sell natural gas to applicants. P. 983.

Charles V. Shannon, Louis Flax, and *Arthur R. Seder* for American Louisiana Pipe Line Company and Michigan Wisconsin Pipe Line Company.

Raymond N. Shibley, J. William Via, Jr., John A. McGuinn, G. R. Redding, and *Wendell J. Doggett* for Panhandle Eastern Pipe Line Company.

Leland F. Cadenhead and *Raymond N. Shibley* for Trunkline Gas Company.

Q. P. Dorschell, Robert S. Hunt, and *John V. Gilhooly* for Village of Savoy, Illinois and Illinois Power Company.

C. V. Hern, Jr., Bradford Ross and *Sherman S. Poland* for Central Illinois Light Company.

Daryal A. Myse for Citizens Gas Company.

Albert J. Feigen for City of LaCygne, Kansas.

J. W. McAuliffe and *Phebe Eppes Gordon* for Battle Creek Gas Company.

John F. Zimmermann for Wisconsin Natural Gas Company and Wisconsin Michigan Power Company.

John C. Lawyer and *Edmund A. Schroer* for Northern Indiana Public Service Company.

N. J. Lesselyoung and *Vernon A. Swanson* for Milwaukee Gas Light Company.

William E. Torkelson for Wisconsin Public Service Commission.

Seymour Tabin for Wisconsin Public Service Corporation.

Robert R. Batton and *Albert L. Harker* for Central Indiana Gas Company.

Robert R. Batton and *Albert L. Harker* for Indiana Gas Distribution Corporation.

Reuben Goldberg and *George Spiegel* for Michigan Gas and Electric Company.

Wilson W. Snyder for the Toledo Edison Company.

*Initial decision appears on p. 969.

William Herron and *Julian De Bruyn Kops* for the Dayton Power and Light Company.

Robert R. Batton and *Albert L. Harker* for Greenfield Gas Company, Inc.

Samuel H. Olsen, David R. Kaplan, and *F. Clifton Lind* for County of Wayne, Michigan.

Robert R. Batton and *Albert L. Harker* for Pendleton Natural Gas Company.

Paul L. Adams and *A. C. Stoddard* for Michigan Public Service Commission.

Gebhard, Hogue & Dwyer for Ohio Gas Company.

John Helm Pratt and *Patrick J. Smith* for Citizens Gas and Coke Utility.

Will W. Reller, Robert R. Batton, and *Albert L. Harker* for Richmond Gas Corporation.

R. P. Duff, J. B. Falahee, James Boorsch, and *J. Phillip Bahn* for Michigan Gas Storage Company and Consumers Power Company.

Elmer Nafziger for Central Illinois Public Service Company.

Glen H. Bell for City Gas Company, Merrill Gas Company, and Wisconsin Fuel and Light Company.

Nathaniel H. Goldstick, and *Robert Reese,* for City of Detroit.

Charles R. S. Anderson for Iowa Southern Utilities Company.

Sprague, Wilcox, and Houts for St. Joseph Light and Power Company.

C. B. Dushane and *E. J. McManus* for Keokuk Gas Service Company.

John E. Fell for Kokomo Gas and Fuel Company.

R. J. Sutherland and *Eugene O. Gehl* for Wisconsin Power and Light Company.

Glen D. Evans for Missouri Public Service Commission.

James D. McKinney, Jr. and *Charles E. McGee* for Missouri Public Service Company.

Sherman S. Poland for Central Illinois Electric and Gas Company.

Thomas F. Ryan, Jr. for Citizens Gas Fuel Company.

Ned Willis for North Central Public Service Company.

Milo J. Fleming, Cecil A. Beasley, Jr., Arthur Weichelt, and *Orville N. Foreman* for Village of Milford, Illinois.

Cecil A. Beasley, Jr., and *Arthur Weichelt* for Village of Louisville, Illinois.

George C. Williams, Robert C. Weber, C. William Cooper, Lawrence L. Gray, and *Norman A. Flaningam* for the East Ohio Gas Company.

Jerome J. McGrath, John A. McGrath, and *Charles W. Stadell* for Mid-West Coal Producers Institute, Inc.

Arthur R. Seder, Jr., Charles V. Shannon, and *Louis Flax* for Michigan Consolidated Gas Company.

Edwin K. Steers, Ira L. Haymaker, and *Donald M. Mosiman* for Indiana Public Service Commission.

Thomas F. Ryan, Jr. for Michigan Gas Utilities Company.

James A. Gammon, John A. McGrath, and *Jerome J. McGrath* for Fuels Research Council, Inc.

James A. Gammon, John A. McGrath, and *Robert E. Lee Hall* for National Coal Association.

James A. Gammon, John A. McGrath, Jerome J. McGrath, and *Welly K. Hopkins* for United Mine Workers of America.

James A. Gammon, John A. McGrath, and *Jerome J. McGrath* for The Chesapeake and Ohio Railway Company.

John F. Gaston for Iowa Electric Light and Power Company.

John H. Groves for Indiana Gas and Water Company, Inc.

Walter D. McQuie, Cecil A. Beasley, Jr., and *John W. Kern, III* for City of Montgomery, Missouri.

Albert J. Feigen, and *Ira D. Beynon* for Ohio Valley Gas Corporation.

Willard S. Stafford for Madison Gas and Electric Company.

Mark McElroy, Andrew R. Sarisky, and *Herbert T. Maher* for Public Utilities Commission of Ohio.

W. F. Laird, Ralph N. Mahaffey, John F. Sisson, and *William C. Hart* for The Ohio Fuel Gas Company.

David R. Goller for Missouri Western Gas Company.

Paul Hess, Cecil A. Beasley, Jr., John W. Kern, III for City of Macon, Missouri.

U. S. Collins, Cecil A. Beasley, Jr., John W. Kern, III, and *Arthur Weichelt* for City of Bushnell, Illinois.

George R. Perrine for Illinois Commerce Commission.

William C. Moore for The Waterville Gas and Oil Company.

Mark McElroy, Andrew R. Sarisky, and *Herbert T. Maher* for Ohio Public Utilities Commission.

Ralph S. Locher and *James L. Harkins, Jr.* for City of Cleveland, Ohio.

Lewis Carroll, William I. Harkaway, William E. Hynan, and *Milton J. Grossman* for Staff of the Federal Power Commission.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

On April 11, 1962, the Presiding Examiner issued his decision in the above-entitled consolidated proceedings, limited specifically to the issues relating to certain Section 7(a) applications and to interveners in the nature of Section 7(a) applicants. His decision was limited to specific parties in the consolidated proceeding who sought gas from Panhandle Eastern Pipe Line Company, Trunkline Gas Company and Michigan Wisconsin Pipe Line Company for service to new communities.

Exceptions were filed by Michigan Wisconsin Pipe Line Company to the decision of the Presiding Examiner on May 1, 1962, contesting certain statements of the examiner concerning the application of Michigan Wisconsin's so-called "10-cent formula."

Upon consideration of the evidence, the briefs filed, the Examiner's initial decision, the exceptions thereto, and the entire record, the Commission finds that the Presiding Examiner's findings and conclusions in the above-listed dockets are supported by the record and should be adopted by the Commission. This finding should not be construed to mean that Michigan Wisconsin Pipe Line Company is necessarily foreclosed from contesting the application of the so-called "10-cent formula" in future proceedings. We find only that it is applicable under the facts and circumstances of these proceedings and that it should apply to the construction of laterals for service to North Central Public Service Company at West Point, Iowa, and Wisconsin Power and Light Company at McFarland, Wisconsin.

The Commission orders:

The Findings and Orders of the Presiding Examiner issued in the above-listed dockets on April 11, 1962, be and they are hereby affirmed.

DECISION

OF THE PRESIDING EXAMINER ON THE ISSUES RELATING TO CERTAIN SECTION 7(a) APPLICATIONS AND TO THE INTERVENERS IN THE NATURE OF SECTION 7(a) APPLICANTS

(Issued April 11, 1962)

ELLIS, *Presiding Examiner:*

Nature of the Case: This is the initial decision of the Presiding Examiner on a group of applications filed by a number of municipalities and distributor com-

panies which have requested an order from the Federal Power Commission directing the pipelines serving their area to establish a facility for the sale of natural gas to them. Most of them also require an allocation from their pipeline supply of a sufficient quantity of gas to serve their needs. The applicants invoke section 7(a) of the Natural Gas Act, 15 U.S. Code 717f(a), or they are interveners who, in the course of their participation in a pending matter of their pipeline, have requested that the Commission attach conditions to the certificate issued to the line to the end that gas service be required to be rendered to them. The intervener-applicants are here treated together with, and in all material respects as, applicants under section 7(a). 3 F.P.C. 598, 606; 16 *id.* 897, 898.

Procedural Background: Beginning well over a year ago, that is on January 31, 1961, hearings have been held practically continuously on pipeline expansion applications filed by the Panhandle Eastern Pipe Line Company and the Trunkline Gas Company and on certain other but related matters involving the American Louisiana Pipe Line Company and the Michigan Wisconsin Pipe Line Company. The principal subject of the hearings was Panhandle Eastern's proposal to abandon its substantial and long continued sale at Detroit to an affiliate of the American Louisiana Pipe Line Company, which has been in litigation for some years,[1] and the consummation of which would have required certain reallocations of the supply of American Louisiana and of another affiliate, the Michigan Wisconsin line. Quite a number of applications by communities along the lines of Panhandle Eastern, Trunkline and Michigan Wisconsin had filed with the Commission applications for orders under section 7(a) of the Natural Gas Act for an allocation of gas for new service to them. Also a number of interveners filed similar requests. The Commission's orders of December 1, 1960, *et seq.*, consolidated all the various matters for hearing, 25 FPC 1137.

Hearings on the group of issues continued through 1961 and were nearing their close on March 1, 1962, when, at the suggestion of Staff counsel, motion was adopted to sever all issues related to the requests for service to the applicant-communities and distributors, to set a final date for rebuttal testimony and for early briefing of these issues (except for two towns whose cases were not immediately terminable). The rebuttal cases were completed on March 2, 1962, and briefs and counterbriefs were to be filed by March 29.

Communities Covered: In the case of the following communities, the projects have been agreed to by the Staff of the Federal Power Commission; all other parties, including the pipelines called upon to serve them, have indicated their concurrence or have voiced no objection (see the hearing transcript at 186T29, 515–8), and no briefs have been received by March 29, 1962, except a very helpful and comprehensive coverage of all the projects in the initial brief of the F.P.C. Staff, and a reply brief on one collateral issue, as discussed below.

Catlin, Illinois
Mount Pulaski, Illinois
San Jose, Illinois
Hume, Illinois
Pesotum, Illinois
Tolono, Illinois
LaCygne, Kansas
Louisville, Illinois
McFarland, Wisconsin
Savoy, Illinois
Sherman, Illinois
West Point, Iowa
Williamsville, Illinois

The applications of two companies to serve Montrose, Iowa, have resolved itself into a certain controversy, which is covered separately. Applications to serve Milford and Bushnell, Illinois, have not yet been fully tried as of the time of this writing, and will be the subject of a later decision. In the case of the fol-

[1] *Michigan Consolidated Gas Company* v. *F.P.C.* (CADC, 1960), 283 F. 2d 204.

lowing towns, the applications have been requested to be withdrawn as a result of changes in the circumstances and no decision with respect to them is contemplated: Omro, Wisconsin; Winneconne, Wisconsin; Tremont, Illinois; and Cerro Gordo, Illinois (see FPC orders of September 26, 1961, and March 20, 1962, and 186T29,468).

The Applicants: The applications for orders from the Power Commission directing the respective pipelines to establish connections and provide service for the communities listed above are grouped as follows:

1. *Panhandle Eastern Pipe Line Company.*

Central Illinois Electric and Gas Company seeks to serve Catlin, Mt. Pulaski, and San Jose, Illinois (intervener).

Central Illinois Light Company seeks to serve Williamsville, Illinois (CP61–114), and Sherman, Illinois (CP61–115).

Citizens Gas Company seeks to serve Pesotum, Illinois (CP61–54), Hume, Illinois (CP61–191), and Tolono, Illinois (CP61–192).

Illinois Power Company seeks to serve Savoy, Illinois (CP61–160).

The City of LaCygne, Kansas, a municipal corporation, seeks to serve that city (CP61–68).

2. *Trunkline Gas Company.*

The Village of Louisville, Illinois, a municipal corporation, seeks to serve that community (intervener).

3. *Michigan Wisconsin Pipe Line Company.*

North Central Public Service Company seeks to serve West Point, Iowa (intervener).

Wisconsin Power and Light Company seeks to serve McFarland, Wisconsin (intervener).

Standards Applied: Following the standards set forth in 15 FPC 1421 and 16 FPC 897, the evidence has been considered for its bearing on the issues essential to a Commission order under section 7(a) of the Natural Gas Act, as follows:

(a) whether the pipeline is the most feasible source of supply;
(b) whether there is public need for, and benefit to be expected from, the service of natural gas;
(c) whether the project can adequately be financed;
(d) whether the project is economically feasible; and
(e) whether the project will unduly impair the pipeline's ability to serve its customers or otherwise unduly burden the pipeline.

See also 17 FPC 118 and 127; 24 FPC 482.

Natural Gas Reserved for New Service: By orders issued July 28, 1961, and September 22, 1961, in these dockets, the Commission issued temporary authorizations to Panhandle and Trunkline and directed the allocation of quantities of natural gas made thereby avaliable. 8,000 Mcf per day were reserved for possible service to new communities and in the interim order to be deliverel to Michigan Consolidated Gas Company.

On March 1, 1962, Panhandle expressed its view that the requests granted for new service in these consolidated proceedings would necessitate the diversion of equivalent quantities of gas from this delivery to Michigan Consolidated, and this position was subscribed to by Michigan Consolidated (186T29,519).

Accordingly, the 8,000 Mcf per day delivery to Michigan Consolidated by Panhandle should be decreased by 4,338 Mcf per day, the amount of gas to be here

allocated to the new communities to be served by Panhandle. This decrease will assure the use of natural gas in accordance with expressed Commission purpose. This covers also the Trunkline community (Louisville). Cf Ex. 49–A.

The two Michigan-Wisconsin distributors will supply the new areas from their present total allotments.

The longer-range needs of the distributors, including those of the new areas, are under continued hearings in these dockets, also in the case of the two Michigan-Wisconsin distributors, they will be considered in another pending expansion proceeding of that line, docket CP62–212, which is Item CB by reference here.

Statistics Respecting the Service Requested: Each applicant presented a fully detailed exhibit, and its operating official was examined and cross examined at the hearing, with the result that there were developed the following data as to each of the 13 projects. The historical figures were presented as actual, while those pertaining to the number and types of customers, the expected gas usage, the initial investment and the operating revenues, were based on the best estimates of the applicants derived from engineering studies of the areas proposed to be served and, in the case of the 11 privately-owned utility projects, upon the experience of the utilities in serving other communities in the general area and developing new projects in the past. The following table collects the data so derived, the cost and other figures essentially being those predicted for the third full year of operation:

Applicant	Cen. Ill. El. & Gas Co.			Cen. Ill. Lt. Co.		Citizens Gas Co.			Ill. Power	City of La Cygne	Village of Louisville	No. Cen.	Wis. P & L
Community	Mount Pulaski	San Jose	Catlin	Williamsville	Sherman	Pesotum	Hume, Ill.	Tolono	Savoy, Ill.			West Point	McFarland
Population	1,687	593	1,272	730	230	500	500	1,550	339	900	1,022	750	1,293
NUMBER OF CUSTOMERS													
Residential:													
Nonheating	119	45	94	57	21	6	12	12	18	0	123	57	85
Heating	279	105	281	243	144	98	68	215	56	385	202	116	252
Commercial:													
Nonheating	29	20	9	8	1	3	4	6	2	0	3	4	9
Heating	20	12	6	33	3	14	6	30	5	23	43	28	27
Ind. or Inst.	2	2	2			2		2		2		3	2
Total Customers	449	184	392	341	169	123	90	265	81	410	371	208	374
Gas requirements:													
Peak day (Mcf)	680	360	615	553	271	324	143	584	102	523	506	327	496
Annual (MMcf)	65.2	42.6	58.5	63.1	29.3	35.1	15.7	63	10.7	51.2	55.8	40.3	59.4
Miles to the pipeline	8.25	1.8	2.9	.6	1.7	2.3	.25	.8	.8	17.4	1.8	4.6	2.
Capital investment:													
Total (thousands of dollars)		548		141	105	89.5	63.2	153	57.5	251	250	91.3	211.6
Per customer (dollars)		535		413.	621.	728.	702.	577.	610	612	674	439.	566.
Operating revenue:													
Income		$188,050		$50,380	$23,340	$31,617	$25,119	$56,722	$10,499	$47,722	$68,624	$44,340	$67,284
Expense		156,350		43,570	20,730	28,288	21,188	52,495	8,141	22,425	33,184	35,590	55,681
Net operating revenue		31,700		6,810	2,610	3,329	3,931	4,227	2,358	25,297	35,440	8,750	11,603
Comparative data:													
Debt service ratio (percent)										1.79	2.23		
Heating saturation	70	70	75	81	87	92.5	82	93	75	10	66	70	75
Home heating usage, cu. ft. per DDD	25.6	25.6	25.6	26.3	26.3					21.	28.2		21.
Peak day Mcf/population unit	.403	.607	.483	.758	1.18	.648	.286	.377	.301	.582	.495	.436	.384
Residential use per population unit	.304	.326	.405	.57	1.07	.316	.22	.223	.257	.529	.328	.24	.275
Peak day Mcf per customer	1.51	1.96	1.57	1.62	1.60	2.63	1.59	2.2	1.26	1.28	1.36	1.57	1.33
Population units per residential customer	4.24	3.95	3.39	2.43	1.39	4.81	6.25	6.83	4.58	2.34	2.14	4.34	3.85
Gross return investment		5.78		4.83	2.49	3.72	6.22	2.76	4.1	10.1	14.2	13.5	6.78

The Projects in Summary

Mt. Pulaski, San Jose and Catlin, Illinois

The Central Illinois Electric and Gas Company has presented a combined exhibit for the three separate unconnected projects, the total investment somewhat exceeding half a million dollars. The company is well established, with assets of $95,000,000, and presently serves both electricity and gas in a number of areas in Illinois. It holds the local franchises from the three communities and a certificate of public convenience and necessity issued by the Illinois Commerce Commission, which on its face satisfactorily evidences the need for the service and the benefit to be derived, as well as its feasibility. The investment per customer, $535, is not unusually large, nor are its predicted usage factors out of line. The figure shown in the table for the residential use per unit of population (.304 Mcf/d for Mt. Pulaski) is derived from (a) the company prediction of .1 Mcf per customer requirement on a maximum day for general use and 1.8 Mcf/d for the entire use of the average residential heating customer, (b) applying those figures to the prediction of the number of customers at the end of the third year in each category, and (c) dividing the total by the population figure cited to us. In the case of Catlin, there are particular indications of community growth upon the basis of which the slightly higher heating saturation figure was derived. Company funds appear to be available to finance the projects and the company is satisfied that it will yield a satisfactory return, at the announced rates, which appear to be comparable to others in the area, and, in any event, are subject to the jurisdiction of the Illinois Commerce Commission.

Williamsville and Sherman, Illinois

These are two small residential towns located a short distance north of Springfield and serving, in effect, as residential suburbs. The Central Illinois Light Company ("CILCO"), which is now the largest general service distributor on the Panhandle Eastern line and serves over 100,000 customers, seeks to add these communities to their service area, on the basis of franchises granted and accepted two years ago and certificates of public convenience and necessity issued by the Illinois Commerce Commission. This is part of its broad program for expansion into a total of ten area communities. A Federal permit is required for these two towns only because the interstate pipeline's branch runs near the town borders, necessitating a tap off the Panhandle line and a regulator station, for which the Federal Power Commission's certificate is required by the Natural Gas Act, 15 U.S.C. 717f.

Williamsville is a town of 730, on U.S. Highway 66, only ten miles north of Springfield. Certain new subdivisions planned for may explain the slightly high estimate of 341 customers after three years, when the net operating income is computed at $6,810, or 4.8 percent of the then investment. Company funds are available for construction (and in Sherman as well), and the project appears to be feasible and necessary in the public interest.

The population figure for Sherman (230) would not support the claimed potential of 169 customers (third-year), on which depends the showing of peak day sales and the resulting operating income of $2,610. This may also explain why the projected gas usage per unit of population is more than double the

actual experience of the company on the peak day of 1960–1961.[3] However, Sherman cannot be considered as a community apart. It is a residential suburb, five miles from Springfield on the main highway, and, as testified by CILCO's Chairman of the Board, Mr. Babcock of Peoria,

> Sherman is located quite close to the Springfield suburban area. There are a number of subdivisions being planned in Section 25 and Section 36 with approximately 150 lots now recently planned for development there. The northern portion of Section 25 approaches the interchange now under construction on the interstate highway system and both residential and commercial development of that area is expected in the near future, which will increase existing demands for natural gas. Approximately 20 residences have been constructed in that area within the last 18 months, and realtors and subdividers are now contemplating additional subdividing. Other utility services are being expanded in that area. Sherman is so located that it is attractive for Springfield workers seeking suburban residences, and particularly in view of its strategic location on a four-lane highway and the new interstate highway. In addition to the promise of substantial expansion in urban residential and commercial development there is the possibility of some industrial development there.

Also, some customers are to be expected off the 1.7-mile lateral to the Panhandle line, and the new subdivisions may have as many as 500 houses (140T22,659–63).[3]

In any event, the Illinois Commerce Commission has jurisdiction of, and responsibility for, authorizing the new service by CILCO, and has issued its certificate of public convenience and necessity for each project. The demonstration before that Commission covered specifically a showing of economic feasibility (140T22,662) and, its certificate, stating there is a "present and anticipated demand in said area" (Ex. 34) and reciting that "the public convenience and necessity require" the project, should conclude examination of, and satisfy the need for establishing, economic feasibility, without the need for a rehearing *de novo* on the same issues, indeed, often on the same proofs. See the concurring opinion of Judge Miller in *Virginia Petroleum Jobbers Association* v. *F.P.C.* (CADC, 1961), 293 F. 2d 527, cert. den. (1961) 368 U.S. 940; see also 15 FPC 1421 at 1427.[4]

Citizens Gas Company of Illinois

This company now serves gas to ten small communities in Eastern Illinois, and in this case seeks pipeline connections from Panhandle Eastern to permit service to three new towns. The program calls for investment of $577 to $728

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[3] CILCO, the distributor for both Peoria and Springfield, has a population of 315,000 and 104,879 customers in the area involved in this case. For its peak day last year (January 24, 1961) the actual gas usage compares (or, rather, contrasts) with the claims or predictions made for Sherman as follows:

	CILCO (PE area)	Predictions for Sherman
Total peak day Mcf, per population unit	.524	1.18
Peak day Mcf for residential use, per population unit	.451	1.07

Computed from exhibits 34, 111–A and 111–C, 140T22,660, 141T22,904.

[3] Springfield metropolitan area's population of 146,539 is nearly double that of the central city alone, and the outlying area has increased by 26.9 percent in the past ten years. Statistical Abstract of the United States (1961, H. Doc. 90, 87th Congress, p. 19).

[4] For the effect of the new F.P.C. regulations, see page 980 below.

per customer, which is lower than in Citizens' recent successful experience in adding service to four other nearby communities (32T5354). The total for the three new towns comes to $305,000, which they plan to finance, one-half from company funds internally generated, the rest by a loan from the State of Wisconsin Investment Board at 5½ percent, Exs. 7A, 235. In all three cases, the town authorities have issued to Citizens a 50-year franchise, and the Illinois Commerce Commission has issued its certificate of convenience and necessity, specifically certifying to the public need and demand for gas service and giving evidence of the feasibility of the project.

Pesotum, a town of 500, has over 200 houses and two new developments started, which will have 250 homes. Perhaps overconservatively, Citizens Gas estimates only 104 residential customers in the third year, 120 in the fifth. As the system grows, the third-year net return of about 2 percent may be expected to increase. The peak day usage to be allowed for (which Citizens will supply out of its present allotment—27T4457) is 324 Mcf/d, which is reasonable for the number of homes in the area. The high usage per customer (2.62 Mcf/d) become only 1.9 when the two institutional customers are subtracted, which compares with 1.84 for Citizens' present seven towns. Ex. 8.

Hume is a residential community of 500 population, located just off the main line of Panhandle. With only ninety customers in immediate prospect, it does not give promise of a sustaining operation until the fourth or fifth year of growth. (Income figures in the table above are for the fifth year; for the other towns, third-year figures are used.) But there is less than a quarter-mile of lateral to install, the customers count and usage figures appear to be quite conservative, and the company is well established, with annual receipts exceeding $1 million, and can well absorb the outlays required during the necessary developmental period. 27T4517, Ex. 7A. In any event, the Illinois Commerce Commission, which has the primary responsibility and which was confronted with the identical project exhibits (32T5346), has issued its certificate of public convenience and necessity, and the question of public demand (as distinguished from the numerical *quantity* needed) and the question of feasibility—if not regarded as determined—should be accepted as satisfactorily proved and established. See page 19, above.

Tolono is a substantial town of 1,550 population, located less than a mile from Panhandle's branch line. On the basis of the markets predicted by Citizens Gas, the staff expresses the view (as in the case of Pesotum and Hume), that Citizens' return on the investment "would not be compensatory at the proposed rates and that a rate increase may ultimately be necessary" (Brief, pp. 10A, 6A, 2A). Nevertheless, (a) it is evident from a comparison of the figures in the table above that the market figures may be considerably understated; (b) Citizens' exhibit claims only 227 house customers in three years, while their house-to-house survey elicited 327 favorable responses (27T4485); (c) the heating saturation predicted in all three towns is slightly less than Citizens Gas' experience in their present seven towns; and (d) the state commission's certificate should allay any doubts, if any such remain, as to feasibility.

Illinois Power Company: This major distributing utility, with $401 million in assets and serving an area 200 miles wide, seeks a "7(a)" order for 102 Mcf/d (third-year) to serve 81 customers in Savoy, Illinois, a small residential suburb with 100 homes located three or four miles out of Champaign-Urbana, in the direction of the growth of the University of Illinois (2T206). It is likened, in fact, to a new subdivision which, except for the detail that a tap is needed off the Panhandle line, would be for consideration by FPC only as included in the utility's overall needs—at the time of the hearing Illinois Power had 17,694 on the waiting list for space heating (8T1356). The town cannot sensibly be

considered apart from the entire Champaign-Urban metropolitan area of 132,436, which has grown 25 percent in ten years, according to the census report cited. In any event, the Company is in a position to finance the investment of $57,500, the customer count is reasonable, and the expected return is adequate. It has a franchise and a state certificate, and no doubt is suggested by the data shown as to economics and feasibility.

LaCygne, Kansas is a rural community of about 900 population, located 55 miles south of Kansas City. The City has applied for a "7(a)" order upon Panhandle Eastern, which, though 17.4 miles away, is the most feasible source of supply.

Differing from the nine utility projects discussed above, this is to be a municipal operation. It does not have the benefit of a state commission certification; in fact, it was testified the state does not control either the inception or the subsequent operation (2T310; 29T4812, and see Kansas General Statutes 66–104). This removes the application from the class of cases in which the state commission's certificate establishes *prima facie* the economic feasibility.

Hence full inquiry was undertaken, with testimony from the Mayor, the consulting engineer, and the finance underwriter. There were especially explored a number of particular circumstances, namely (a) the cost of the lengthy transmission lateral; (b) the claim that 94 percent of the potential market would be sold, and at virtually 100 percent heating saturation; (c) the legal and finance fees totalling 5.38 percent and engineering at 7 percent; (d) the low cost planned for the distribution system itself ($166 per customer); and (e) the validity of the plans for bond issues.

In all its phases the program has the benefit of experienced engineers and underwriters. The engineering witness has installed eleven comparable projects, all of which have proved successful, and the market usage, and cost figures were derived in part from that experience. The finance witness also testified to the City's credit standing, his firm's experience in many similar undertakings, and their agreement to purchase the bonds.

While the program calls for an unusually long transmission lateral (17.4 miles), there was presented a contractor's firm bid at only $1.57 per foot for a 4 inch line, much less than such costs for the Illinois projects. Right of way cost is to be inconsequential, and there will be some customers en route. The same contractor has furnished an equally favorable bid for the distribution system, and there is a comparative study showing that the bid prices about equal the experience of seven other small communities.

The unusually high ratio of heating customer attachments is supported by (a) the town vote for a gas system, which was approved 255 to 49; (b) the factor that most houses there now heat with propane, which is more expensive; (c) the engineering firm's consistent pattern of experience in other communities in the locality in some of which, in fact, the consumers have signed up 100 percent for space heating, (2T222; 29T4820); and (d) the cost study showing a favorable margin under oil heating costs.

The financing is arranged in the form of general obligation bonds, $180,705 at 4¾ percent for twenty years, and 5 percent revenue bonds of $70,000 for thirty years. The First Securities Company of Wichita will purchase both issues, for a 4 percent fee (2T283). The record is to the effect that the amount of the first issue will not exceed the statutory debt limit (2T293). The annual net revenues—based on the sales predicted—are ample to provide a satisfactory coverage of the debt service charges, at a ratio of 1.79. It is evident that, before the citizens' vote on the project, they were made fully aware of the conceivable call upon the general taxpayers for possible support of the general obligation bonds (2T281; 29T4865).

Upon the facts stated, the predictions employed, and the several favorable judgments recited, the feasibility of the project may be regarded as satisfactorily demonstrated, but there may be subjoined the reminder that, quoting from 15 FPC 1421, at 1429, footnote 1:

> Of course, these findings do not constitute an endorsement of the foregoing projects, nor is endorsement given to any estimates, fees, or projected method or manner of operation contained in the engineering reports or shown by the testimony. Investors in the securities to be issued must exercise their own judgment upon these questions. As we stated *In re Carolina Natural Gas Corp.*, 10 FPC at page 515, "the Commission can assume no responsibility to potential buyers of securities with respect to the success or failure of a (local) distribution system."

See also 67 Public Utilities Fortnightly 281 (1961).

Louisville, Illinois: This is a municipal project, calling for an order upon the Trunkline Gas Company to make a connection with its line and sell 506 Mcf/d for the use of that town. Since it is a public project, it does not have the benefit of a state commission's certificate of convenience and necessity. However, the facts were fully developed and, as shown in the table above, establish *prima facie* a satisfactory operation.

Experienced engineers were employed, and their predictions of gas usage are based on the records in 37 more or less comparable projects. The estimate of 202 residential gas heating customers out of 402 homes in the area is acceptable on its face (30T4962), and is based on substantially complete conversion of the present users of propane and upon the assumption that nearly ⅓ of the oil heating residents will convert to gas by the third year, since the gas will be 27 percent cheaper (30T4949, 5002).

The construction cost is not patently out of line in view of the population and the customer potential. The total estimated cost of the project is $250,000, to be raised through five percent, 30-year, gas revenue bonds. The estimates of construction costs were raised about 25 percent over current bids "as a factor of safety." However, Louisville will be obligated to issue bonds only sufficient to cover the cost of actual construction (30T5019). Midwest Securities Company of Chicago will purchase the issue (3T471, 30T5022), at a discount of not more than ten percent, depending upon the bond market at the time. It is estimated that the discount will be probably very close to the ten percent limit (30T5019, 5028–5030), thus the actual interest rate to Louisville would be at 6.30 percent (30T5053). The debt service coverage ratio is 2.23, based on 30 years (Ex. 38, p. 15).

The town vote taken in accordance with the Illinois statutes (Ch. 24: 49-3) was 384 to 5 in favor of the municipal project and it was testified that the proposed rates and conversion costs had been publicized before the vote (2T352; 30T4944, 5062). The financing firm which has undertaken to buy the bonds has had wide experience in Illinois municipal projects, all of which were said to have proved successful and in fact it was testified, "There never has been a default in Illinois on any natural gas municipal system." (3T466, 30T5042).

The evidence establishes satisfactorily the economic feasibility of the project, the legal capacity of the village to engage in the function, the need for the gas service, and its desirability in the public interest. Trunkline stated on the record that it "has no objection." (123T20,054).

North Central Public Service Company for service to West Point, Iowa

History of the Application Before F.P.C.: The proposal of this company to serve West Point, Iowa, is part of a program that first came before the Federal

Power Commission, in the very present docket, seven years ago, at which time the North Central Public Service Company requested allocation of gas for service to West Point and two other towns in Iowa. The services were not to be from the same lateral, but the program was considered as a joint one. The application was not then rejected, but there were expressed some doubts about feasibility because of the expense of the lateral required to be built. The result was that the Commission's order of September 4, 1956, in this docket (G–2306, 16 F.P.C. 897, 902, 910) "deferred" decision on the joint project pending consideration of the policy question which arose as to whether the pipeline (Michigan Wisconsin) should share the burden of the cost of the laterals leading from its line to the city gates of prospective new distributor customers. At page 902 it is said, "Accordingly, it is appropriate that the question whether Michigan Wisconsin should be required to construct the laterals involved in the projects of Iowa Electric, Iowa Southern and North Central and these parties' related applications be deferred pending such further consideration."

Thereafter North Central made another presentation in this same case, through testimony and exhibits presented on May 28, 1957, also on July 16, 1957. The present, or third, phase of G–2306 (and its related docket in the name of the Michigan Wisconsin Pipeline Co., G–2327) began with the Commission's order of December 1, 1960, which is discussed at pages 11 and 12 above. Following the direction contained on page 20 of that order, North Central reasserted its interest as an intervener and at the time of its opening testimony in this case on February 17, 1961, 14T2308, reintroduced its proposal to serve the town of West Point. The admission of the exhibit was objected to by Panhandle Eastern on the basis of (a) irrelevance, (b) the lack of formal "7(a)" application, and (c) the lack of notice of the issue raised by the exhibit, that is, the need of the new community (14T2321). The exhibit was admitted, and with it the issue it raises, on the basis that the West Point proposal had been considered as a result of North Central's previous intervention in G–2306, G–2327, and the order of December 1, 1960, permitted prior interveners to participate in the present proceeding merely on the basis of filing a notice to that effect, which requirement North Central had complied with. The "law of the case" is found in the Commission's 1956 decision in this docket, 16 F.P.C. 897, 898, stating that in passing upon the request here, "No distinction need be made between the request for natural gas of Section 7(a) applicants and interveners. All such requests may appropriately be judged under the requirements of Section 7(a)."

The Applicant: The intervener which is requesting an order for a supply from the Michigan Wisconsin line is the North Central Public Service Company of St. Paul, a private utility serving a number of areas in Iowa and Minnesota as well as the city of Fort Madison in southeastern Iowa on the Mississippi River. North Central's proposal is to serve the small, nearby community of West Point, population 750, which is located a few miles inland from Fort Madison. Since there will be required a 4.6-mile lateral from the Michigan Wisconsin pipeline to reach West Point, also a new tap off the pipeline, the matter becomes involved before the Federal Power Commission and requires a certificate or order under Section 7 of the Natural Gas Act. Originally, the applicant sought also an increase in its daily contract supply from the line in order to supply the new area, but at the present hearings it agreed specifically that it could and would serve West Point out of its present daily quantity provided in its agreement with Michigan Wisconsin (14T2326, 2343, 44T7700). However, since the tap and other facilities are to be covered under a Section 7 order, North Central's request remains in the case for determination.

Local Authority: A local franchise was secured in 1955 and another in 1961, affirmed by a popular vote of 72–7 (Ex. 145–B). With respect to a state cer-

tificate, it is agreed that Iowa no longer, at least, maintains a state commission with jurisdiction in the present matter (37T6,498). Rather, each town issues the authority in the form of a non-exclusive franchise, but with local control retained over the rates (37T6,509, 186T29,345). Cf. Iowa Code, sections 474.10 and 490; 397.

Feasibility: The markets anticipated, as set forth in the table above, are well within the range to be expected; they are quite close to the figures attained in other towns in the general area (44T7,688, Ex. 145); and they are supported in part by a showing that gas heating will cost somewhat less than oil (44T7,650). The company is prepared to finance the construction (Ex. 145, p. 17), which will be carried out by North Central or by an affiliate (14T2,362). The connecting line is to be 4.6 miles long, but under its lateral-sharing program (as discussed below), the Michigan Wisconsin Pipe Line Company will build one-third of the distance, for about $26,000. Deducting that figure from the total costs of the project, the resulting investment per customer becomes a very modest $312, and the ratio of gross return to investment is over 13%.[5] Feasibility is satisfactorily established.

Wisconsin Power and Light Company for service to McFarland, Wisconsin

McFarland is a small but fast-growing residential suburb five or six miles out of Madison, Wisconsin, and only two miles from the Michigan Wisconsin pipeline. The town has enfranchised Wisconsin Power and Light Company—already the local electric utility—and that company, having now obtained a State certificate of public convenience and necessity, has requested an order from the Federal Power Commission for an attachment to the pipeline in order to serve 496 Mcf/d to 374 customers out of the population of 1,293.

Wisconsin Power and Light Company is a very substantial utility, serving 40,000 gas customers in 16 areas (16T2,570) and is in a position to finance the extension of service into McFarland (16T2,582, 67T11,340). The distributor serving Madison offers no opposition, saying only, "They have the franchise." (61T10,435).

The usage factors predicted appear normal, are based on the company's experience elsewhere, and contemplate attaching 80% of the potential market in three years, three-fourths of them for space heat. (It is noted that over half of the present householders are already propane users.) The company computes a 5½% rate of return (16T2,587). As in the case of West Point, Michigan-Wisconson agrees to the request for service (116T18,968).

No question as to economic feasibility appears from the facts stated and figures in the above table; in any event the state commission required a demonstration of feasibility (67T11,311, 186T29,475) and its certificate would allay any question, if any such there were. Note in this connection, the recent amendment to the Federal Power Commission Regulations Under The Natural Gas Act which eliminates a number of the exhibits required for a "7(a)" application *when* there is presented a state commission's certificate of public convenience and necessity. Regulations, section 156.5(a)(15). While this change was effective after the present case began and after the interveners made known their requests for gas service, it is necessarily to be inferred that the state certificate will be looked

[5] The net revenue of $8,750, on which this percentage depends, was obtained by subtracting from the gross receipts a computed share of the combined costs of operation of West Point and of another town. These costs, shown jointly, have been pro-rated according to the ratio of the respective gross receipts (Ex. 145, p. 20).

upon, in an otherwise proper case, as supplying the basic or *prima facie* showing for the purpose of which the omitted financial exhibits would otherwise be required. (See also page 975, above.)

Michigan-Wisconsin's lateral-sharing formula

One detail remains affecting West Point and McFarland, which are to be served from the Michigan-Wisconsin line. It relates to the cost of the laterals from those towns to the line, 4.6 and two miles, respectively. Staff witness Johnson proposes the application of a formula, apparently peculiar to Michigan-Wisconsin but applied in quite a number of cases in recent years, under which the pipeline company is called upon to underwrite or contribute to the cost of the lateral up to a certain sum, as determined by the formula. Unclear—indeed eseteric—in its details, what it results in is a figure of two-thirds of a dollar for each Mcf in the annual sales to the distributor which are in view for third year of operation. For North Central this could mean about $26,000, or one-half of its lateral cost to West Point. For Wisconsin Power and Light, it may approximate $40,000, or about all of its cost.

North Central counts on this cooperation, to insure the project's feasibility (14T2,362, 37T6,522, Ex. 145, p. 22). The Wisconsin firm at first disclaimed interest in it, apparently feeling it would lead to controversy and delay, but later indicated it would accept the arrangement if offered (16T2,584, 67T11,321, 11,333).

Michigan-Wisconsin equivocates even more. At least one policy statement at the hearing disclosed that the formula was fully expected to apply (116T18,968). Other statements dispute its application here because the orders contemplate no direct, specific increase in the daily quantity which the distributor expects to sign up and pay for. (44T7,752, 186T29,498). Finally, in its reply brief filed March 29, 1962, Michigan-Wisconsin comes to the conclusion—as nearly as it can be divined—that it does not object to an order specifying the formula so long as it is not to be regarded as contradicting its objection in principle, as just noted.

It may be the objection has its proper place in a proper case, but not here. For both towns, the new taps and the new laterals will open up entirely new markets to the service of Michigan-Wisconsin, in areas not now served at all, with new customers in homes and establishments not now using natural gas, whose needs, modest though they be comparatively, will now have to be considered in the pipeline's total program. Thus the objection loses force and reality. Both distributors will be seeking higher contract quantities, and the new market areas will contribute to their proof of need and ability to pay.

Accordingly, in line with numerous precedents,[6] the formula will be here applied, but it cannot be stipulated that this action will not later be listed as a precedent for cases where the new laterals open up new and otherwise unreachable market areas and thus, in the long run, necessarily result in increased daily contract quantities.

FINDINGS AND CONCLUSIONS

Upon consideration of the evidence, it is further found and concluded that:

(1) Michigan Wisconsin Pipe Line Company, Panhandle Eastern Pipe Line Company and Trunkline Gas Company are "natural-gas companies" within the meaning of the Natural Gas Act. Each is respectively the most feasible source of supply for the several applicants herein.

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[6] 21 FPC 552, 558; 22 FPC 1157; 24 FPC 177, 181; and see *Michigan Gas and Electric Company* v. *F.P.C.* (CADC 1961), 290 F. (2d) 374, n. 1.

(2) Each of the following applicants, namely:

Central Illinois Electric and Gas Company;
Central Illinois Light Company;
Citizens Gas Company;
Illinois Power Company;
North Central Public Service Company;
Wisconsin Power and Light Company;
City of LaCygne, Kansas;
Village of Louisville, Illinois,

is a "person or municipality legally authorized to engage in the local distribution of natural gas to the public" within the purview of Section 7 of the Natural Gas Act.

(3) The extension of transportation facilities, the establishment of physical connection, and the sale of natural gas by the companies set forth in finding No. (1) to the distributors or municipalities set forth in finding No. (2), will not place an undue burden upon the companies set forth in finding No. (1), or impair their ability to render adequate service to their customers.

(4) It is necessary and desirable in the public interest that Panhandle Eastern Pipe Line Company be directed to establish physical connection of its transportation facilities with the facilities proposed to be constructed by and to sell up to the following natural-gas requirements to:

	Per day
	Mcf
Central Illinois Electric and Gas Company:	
Catlin, Illinois; Mt. Pulaski, Illinois; San Jose, Illinois, total	1,655
Central Illinois Light Company:	
Sherman, Illinois	271
Williamsville, Illinois	553
Citizens Gas Company:	
Hume, Illinois	143
Tolono, Illinois	584
Illinois Power Company: Savoy, Illinois	102
City of LaCygne, Kansas	524

(5) Panhandle Eastern Pipe Line Company should be directed to establish physical connection of its transportation facilities with the facilities proposed to be constructed by Citizens Gas Company for the delivery of natural gas in the Village of Pesotum, Illinois.

(6) Trunkline Gas Company should be directed to establish physical connection of its transportation facilities with the facilities proposed to be constructed by and to sell up to the following quantity of natural gas to:

	Per day (Mcf)
Village of Louisville, Illinois	506

(7) Panhandle Eastern Pipe Line Company should be directed to decrease the volume of gas which it has been required to deliver to Michigan Consolidated Gas Company (by orders of the Federal Power Commission, issued July 28, 1961, and September 22, 1961, in these proceedings) by the volume of gas for new service which it is ordered to deliver to the persons or municipalities set forth in finding No. (4), and by the amount which Trunkline Gas Company is ordered to deliver to in finding No. (6).

(8) Michigan Wisconsin Pipe Line Company should be directed to establish physical connection of its facilities with those proposed to be constructed by North Central Public Service Company for the service of natural gas in West

Point, Iowa, and with those proposed to be constructed by Wisconsin Power and Light Company for the service of natural gas in McFarland, Wisconsin.

(9) Michigan Wisconsin Pipe Line Company should be directed to improve and extend its transportation facilities to the extent determined by the application of the lateral-sharing formula as herein provided, and to establish and maintain physical connection of its transportation facilities as set forth in finding No. (8) in accordance therewith.

ORDER

WHEREFORE, It is ordered, subject to review by the Commission, that:

(A) Panhandle Eastern Pipe Line Company establish physical connections of its transportation facilities with the facilities proposed to be constructed, as set forth in findings Nos. (4) and (5), sell and deliver the additional volumes of natural gas set forth in finding No. (4), and make the delivery for Pesotum referred to in finding No. (5).

(B) Panhandle Eastern Pipe Line Company decrease by 4,338 Mcf per day the volume of natural gas which it has been required to deliver to Michigan Consolidated Gas Company, as set forth in finding No. (7).

(C) Trunkline Gas Company establish physical connection of its transportation facilities with the facilities proposed to be constructed and sell and deliver the required volumes of natural gas, as set forth in finding No. (6).

(D) Michigan Wisconsin Pipe Line Company improve and extend its transportation facilities to the extent determined by the application of the lateral-sharing formula as herein provided and set forth in finding No. (9), establish and maintain physical connections of its transportation facilities with the facilities proposed to be constructed, and deliver and sell natural gas, as set forth in finding No. (8), but Michigan Wisconsin Pipe Line Company is not by this order required to sell additional quantities to those named in finding No. (8).

WILLIAM L. ELLIS,
Presiding Examiner.

ADDENDUM

On Friday, April 6, after the foregoing had been prepared and its distribution was in process, there was received the Staff's—

MOTION FOR LEAVE TO FILE ANSWER TO REPLY BRIEF OF MICHIGAN WISCONSIN PIPE LINE COMPANY, AND, IN THE ALTERNATIVE, MOTION TO STRIKE PORTIONS OF REPLY BRIEF OF MICHIGAN WISCONSIN PIPE LINE COMPANY

The motion is denied on the grounds—

(a) *Procedural:* The briefing schedule as arranged on March 1, 1962 (186T29,506, 29,509, 29,514, 29,521, 29,528 and 29,529), called for initial briefs by March 15 and any reply briefs by March 29. As particularly pointed out by the Staff, this program did not contemplate reply briefs *to* reply briefs (186T29,526). Also, the reply brief of Michigan Wisconsin does not raise its objection for the first time—in fact it was brought up at least as early as the hearing of the Staff witness on March 1, 1962, 186T29,498.

(b) *Substantive:* The motion appears to pertain to the lateral-sharing formula of Michigan Wisconsin. All parties are in agreement as to the application of the formula in this case, and that application is provided for in the conclusions above-stated. Hence any discussions about precedents or limitations are moot and immaterial.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

EL PASO NATURAL GAS COMPANY, DOCKET NO. G–16235; EL PASO NATURAL GAS COMPANY DOCKET NO. G–16237; COLORADO INTERSTATE GAS COMPANY, DOCKET NO. G–16904

ORDER DENYING MOTIONS TO OMIT INTERMEDIATE DECISION AND DIRECTING THE PRESIDING EXAMINER TO MAKE FINDINGS

(Issued May 17, 1962)

1. We have before us for consideration motions by El Paso Natural Gas Company and Colorado Interstate Gas Company, Idaho Public Utilities Commission, Washington Utilities and Transportation Commission, and Public Service Commission of Wyoming to omit the intermediate decision by the presiding examiner in the above proceeding. Those motions are supported by some of the interveners, namely Natural Gas Pipeline Company of America, Public Service Company of Colorado, Southern California Gas Company and Southern Counties Gas Company of California, City of Colorado Springs, and City of Pueblo; and they are opposed by other interveners, namely Tennessee California Gas Company (Tenn-Cal) and California Gas Transmission Company (CalGas), Southern California Edison Company, Transwestern Pipeline Company, the oil companies, and the Commission's staff.

We have given careful consideration to the arguments supporting and opposing waiver of the intermediate decision. We fully recognize the public interest which favors expediting the determination of this proceeding, particularly as it relates to the needs of Colorado Interstate Gas Company for early action to improve existing facilities for serving its customers in the Rocky Mountain area. But even assuming that we could legally waive the intermediate decsion, in view of the fact that the proceeding involves *inter alia* abandonment applications (See *Chotin Towing Corp.* v. *F.P.C.*, 250 F. 2d 394 (C.A.D.C.)), we do not believe that, even in the absence of the additional complications referred to below, this is the type of proceeding in which we could effectively perform our decisional function in the absence of a recommended decision by an examiner who is more familiar than we are with the extensive record in the case. We shall therefore deny the motions to omit the intermediate decision in this proceeding.

2. We believe, however, that we are in a position at this time to bring to a head for early determination the important question of whether this proceeding can be decided independently of the pending proceeding regarding the Pemex project, *Southern California Edison Co., et al.*, Docket Nos. CP61–172, *et al.* In our order of September 13, 1961, in this proceeding in which we permitted Tenn-Cal and CalGas to intervene, we made clear that we had not decided and were not then deciding the ". . . question of mutually exclusivity of the Rock Springs project and the Pemex project and of the applications involved in them, respectively." But we also made clear that since Southern California Edison Company (Edison) is one of the largest customers of the Southern California Gas Company (Southern) which would be served by the Rock Springs project, and since one of the major objectives of the Pemex project is to provide Edison with a source of gas supply independent of Southern, it would be necessary for El Paso to adduce evidence in the reopened Rock Springs proceeding showing whether or not that project would be economically feasible on the assumption that Edison might cease to be a customer of Southern. Evidence with respect to this issue has presumably been introduced into the record in this proceeding.

We have given further consideration to the relationship between the Rock Springs and Pemex projects in the light of the decisions of the courts in such

cases as *Ashbacker Radio Company* v. *F.C.C.*, 326 U.S. 327 : *Midwestern Gas Transmission Co.* v. *F.P.C.*, 258 F. 2d 660, 666–668 (C.A.D.C.) ; *Delta Airlines, Inc.* v. *C.A.B.*, 228 F. 2d 17 (C.A.D.C.) ; and *Delta Airlines, Inc.* v. *C.A.B*, 275 F. 2d 632, cert. denied, 362 U.S. 969. It is our opinion that, even assuming that we might grant the applications in the Rock Springs project if we should determine that that project would be economically feasible and otherwise consistent with the public interest were Edison to be lost as a customer to the companies receiving gas from the Rock Springs project, such action might prejudice the rights of the applicants in the pending Pemex proceeding by resulting in a changed factual situation having a substantial adverse impact upon the likelihood that we could subsequently grant the applications involved in the *Pemex* case. Specifically, we are of the opinion that if the record in Rock Springs indicates there would be a substantial excess capacity in the Rock Springs pipeline for a number of years following its completion (assuming that Southern California Edison is lost as a customer to Southern California Gas Company) this would be a factor which we would necessarily have to take into account in determining whether the public interest would be served by also granting the applications for the Pemex project.

Such a situation would, in our opinion, bring the present proceedings within the ambit of the *Ashbacker* rule, and require, or at least make advisable, simultaneous consideration of the two proceedings rather than any determination of Rock Springs in advance of Pemex. We recognize, of course, that it might eventually develop that either Rock Springs or Pemex, or both, should be denied on their own merits, irrespective of the impact of the other proceeding, or, conversely, we might eventually determine that both projects should be granted. But as we understand the *Ashbacker* rule, which is essentially a rule of basic fairness, it prescribes that there should be joint consideration of two applications not only where it can be determined in advance that they are in fact mutually exclusive, but also whenever it appears that prior action on one will seriously jeopardize the chance of the other being granted. As the court of appeals stated in *Midwestern Gas Transmission Co.* v. *F.P.C.*, *supra*, at p. 668, "The Commission should not adopt procedures that foreclose full inquiry into broad public questions, either patent or latent."

While there are a number of factors which might make a comparative determination necessary or advisable here, and while the *Midwestern* case, *supra*, at 670, emphasizes that this problem is not to be limited to "issues pressed by the applicants", there is one area where we believe we may be in a position to determine now that comparative consideration of Pemex and Rock Springs should be ordered. Accordingly, we shall direct the examiner to submit to the Commission and serve upon the parties and staff counsel within 30 days from the date of issuance of this order a special finding with respect to the extent and nature of the excess pipeline capacity, if any, now available to serve California. Such finding should deal also with the extent and nature of the excess capacity, if any, which could be expected to exist as a result of the certification by the Commission of the Rock Springs project, and also in the event that Edison ceases to be a customer of Southern and other companies which would be served from the Rock Springs project. Such finding should set forth the excess pipeline capicity, if any, which would exist at the time of the completion of contruction and at various periods thereafter to the extent that the record provides a basis for such estimates.

Since this finding is not to be used in deciding whether to grant or deny the applications in this proceeding, but merely to assist the Commission in determining whether or not to consolidate this proceeding, with the Pemex proceeding, it

is not believed that the provisions of Sections 7 and 8 of the Administrative Procedure Act are applicable. However, upon receipt of the examiner's special finding, which of course will be a part of the record in this proceeding, we shall afford all of the parties to the proceeding a period of 20 days within which to file such pleadings, statements of position or written argument as they may wish directed either to the factual finding made by the examiner or to the legal question of whether in the light of such finding a comparative consideration of the Rock Springs and Pemex projects is required.

3. In addition to the foregoing, a separate problem relating to the future of this proceeding has been raised by the decision of the Supreme Court on April 30, 1962, in *People of the State of California* v. *Federal Power Commission*, No. 187, October Term 1961. In that case the Court reversed the action of the court of appeals in affirming our granting approval of the acquisition by El Paso of the assets of Pacific Northwest Pipeline Corporation, holding that the Commission should have awaited the decision in the pending antitrust action against El Paso before concluding action on El Paso's application to acquire the assets of Pacific Northwest. We shall deal subsequently with the general problem of the manner in which the mandate of the court should be complied with pending resolution of the antitrust action. But insofar as the present proceeding is concerned, it is evident in the light of the Supreme Court's action in the *California* case, *supra*, that for the foreseeable future we will be unable to determine whether the Rock Rock Springs project should be considered as a project of El Paso Natural Gas Company (including Pacific Northwest), or whether it will have to be considered as a project of a reconstituted Pacific Northwest. For it seems clear that this project (which was initiated at a time when Pacific Northwest Pipeline Corporation was a corporate entity) relates directly to that part of the present El Paso system which previously was a part of Pacific Northwest, and, presumably, would be a part of a reconstituted Pacific Northwest.

We could, of course, await the final resolution of the status of the El Paso-Pacific Northwest merger before attempting to resolve that question. However, the Commission does not wish to add avoidable delays to the unavoidable ones. We believe, therefore, that it is in the public interest that to the extent feasible, we ascertain now whether the record in this proceeding is sufficient to serve as a basis for a decision on the merits of the applications here involved regardless of whether Pacific Northwest is reconstituted as a corporate entity or remains merged into El Paso.

We shall, therefore, direct the examiner to make and file with the Commission and serve on the parties and staff counsel at the same time he files his special finding described in paragraph 2 above, a finding in writing as to whether the record does contain sufficient information to form the basis of a decision on the merits of the applications, assuming that Pacific Northwest will be reconstituted as a separate corporation apart from the El Paso system. As in the case of the special finding, we shall permit the parties to the proceeding to submit pleadings, statements of position or written comments directed to the examiner's determination of this issue, as well as to submit comments relative to the feasibility and the advisability of reopening the record to introduce such further evidence as they might deem to be necessary with respect to the ability and willingness of a reconstituted Pacific Northwest to undertake the Rock Springs project, and also as to whether grant of any such authority to a reconstituted Pacific Northwest would serve the public interest.

Upon careful consideration of the arguments for and against the motions to omit the examiner's decision, we find that the public interest requires that said motions be denied.

The Commission orders:

(A) All motions to omit the examiner's intermediate decision in this proceeding are hereby denied.

(B) The presiding examiner to submit to the Commission and serve upon the parties hereto and the Commission's staff counsel, within 30 days after the issue date of this order, a special finding in writing with respect to excess gas pipeline capacity, if any, available to serve California markets as described in paragraph 2, above, and, simultaneously, a finding in writing as to whether the record in this proceeding is sufficient to form the basis of a decision on the merits of the applications in this proceeding, assuming that the Pacific Northwest Pipeline Corporation will be reconstituted apart from the El Paso system, as described in paragraph 3 above.

(C) All parties to the proceeding and staff counsel to file within 20 days of issuance of the examiner's special findings with the Commission and serve upon other parties and staff counsel such responses as they deem necessary, within the purview of this order, to the special findings of the examiner.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

KANSAS GAS AND ELECTRIC COMPANY, DOCKET NO. E-7033

ORDER AUTHORIZING ISSUANCE OF COMMON STOCK

(Issued May 17, 1962)

Kansas Gas and Electric Company (Applicant), a corporation organized under the laws of the State of West Virginia and doing business in the State of Kansas, with its principal business office at Wichita, Kansas, filed an application on April 3, 1962 for authority, pursuant to Section 204 of the Federal Power Act, to issue 2,350,000 additional shares of Common Stock, without par value, for a reclassification, or split, of the outstanding Common Stock of Applicant.

Applicant proposes, subject to the approval of its Common Stockholders: to increase the number of shares of Common Stock authorized to be outstanding from 4,000,000 to 8,000,000; and, to split on a two-for-one basis the Common Stock presently outstanding in the amount of 2,350,000 shares, without par value, through the issuance to each Common Stockholder of record at the close of business on May 23, 1962 of one additional share of Common Stock for each share held. The aggregate capital represented by Applicant's Common Stock will not be changed as a result of the proposed two-for-one split.

Applicant states that the proposed Common Stock split should result in a broadening of public interest in Applicant's Stock, an increase in the number of Stockholders, and a greater availability of shares of its Common Stock for purchase and sale.

Written notice of the application has been given to the State Corporation Commission of Kansas and to the Governor of that State. Notice has also been given by publication in the Federal Register on April 13, 1962 (27 F.R. 3574), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before May 2, 1962, with the Federal Power Commission, Washington 25, D.C. No protest, petition or request to be heard in opposition to the granting of the application has been received.

736-330—64——65

The Commission finds:

(1) Applicant, a corporation, is a public utility within the meaning of Section 204 of the Federal Power Act, subject to the jurisdiction of the Commission, as heretofore described and set forth in the Commission's order issued December 31, 1959, *In the Matter of Kansas Gas and Electric Company*, Docket No. E–6914 (22 FPC 1191).

(2) The proposed issuance of Common Stock, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204 (f) of the Act, and the proposed issuance of Common Stock, as described above, is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance of Common Stock, as described above, is exempt from the competitive bidding requirements of Section 34.1a of the Commission's Regulations under the Federal Power Act by reason of paragraph 34.1a(a)(1) thereof.

(5) The proposed issuance of Common Stock, as hereinafter authorized, will be for a lawful object, within the corporate purposes of Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purposes.

The Commission orders:

(A) The proposed issuance of Common Stock, as described above, upon the terms and conditions and for the purposes specified in the application, is hereby authorized, subject to the provisions of this order.

(B) This authorization shall expire unless the transaction hereby authorized is consummated within 90 days from the date of issuance of this order.

(C) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuations, estimates or determinations of costs, or any other matter whatsoever which is now pending or which hereafter may come before this Commission or any other regulatory body.

(D) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States in respect to any securities to which this order relates.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

NEW YORK STATE NATURAL GAS CORPORATION, DOCKET NOS. G–17296, G–19087, AND G–20109

ORDER DENYING APPEAL FROM RULING OF PRESIDING EXAMINER[1]

(Issued May 17, 1962)

Pursuant to Commission order issued herein on November 21, 1961, and upon a hearing date fixed by notice from the Secretary, the hearing in these consolidated proceedings in which 15 parties are participating began on May 1, 1962.

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[1] Motion requesting recess and settlement conference is herein considered as an appeal from a ruling of the Presiding Examiner under Section 1.28 of the Commission's Rules of Practice and Procedure.

These proceedings under Section 4 of the Natural Gas Act involve determination of the just and reasonable rates and charges for natural gas supplied by New York State Natural Gas Corporation (New York Natural) to its customers from facilities extending 470 miles from the West Virginia-Pennsylvania border northeastward into New York State as far as Albany.

Conferences for the settlement of these proceeedings have heretofore been held and have failed to achieve settlement.

The prepared testimony and exhibits of New York Natural were served on March 1, 1962. As an aid to expeditious hearing, the staff serviced its prepared testimony and exhibits prior to the commencement of the hearing.

On May 2, 1962, at the outset of cross-examination of New York Natural's witnesses counsel for North Penn Gas Company (North Penn) adverting to the availability of the staff's case and the aid thereby afforded, moved by oral statement that the hearing be recessed for the purpose of entering upon a settlement conference. The Presiding Examiner denied said motion and stated his reasons therefor at transcript pages 579 through 582, which pages have been certified to the Commission.

On May 3, 1962, North Penn filed with the Commission its motion requesting recess and settlement conference. Thereafter on May 4, 1962, the Presiding Examiner further explained his reasons for denial of North Penn's oral motion at this time which Movant seeks to have overruled. The explanation is set forth on transcript pages 732 through 749 which have been certified to the Commission. North Penn's motion is here considered as an appeal to the Commission from a ruling of the Presiding Examiner under Section 1.28 of the Commission's Rules of Practice and Procedure.

In substance, the Presiding Examiner considered that upon the basis of the record then existing and his examination of the two cases served upon the parties, a settlement conference at that juncture was premature. It is the Examiner's view that more than dollars and the distribution of a cost of service among the customers is in issue; that the explanation of the failure of prior settlement conferences lay in certain ill-defined issues and neglect of issues; and that more could be accomplished in the way of expediting either settlement or conclusion of the hearing by continuing through the complete cross-examination of New York Natural's case.

It is the Commission's policy to encourage settlements which promote the public interest. However in this instance the Presiding Examiner evidently finds the inter-corporate relationships among New York Natural and its affiliates as well as the operating mechanism of New York Natural to be unusually complex. It appears that such complexity runs, among other things, to accounting matters, to past certifications of public convenience and necessity, and to problems of disparity in rates and charges to affiliated versus non-affiliated customers. In short, the Presiding Examiner finds need for discovery of issues, for clear definition of issues and for the development of evidence by formal procedure prior to any settlement conference. This objective promises to serve not only a settlement conference but also expeditious disposition of the case if any subsequent settlement conference were to fail. Thus it appears that the Presiding Examiner has properly set a course for either settlement or disposition of the case by hearing and decision.

The Commission finds:

Good cause has not been shown for overruling the Presiding Examiner's denial of North Penn Gas Company's oral motion for a recess and settlement conference and the appeal therefrom, filed with the Commission should be denied.

The Commission orders:

North Penn's motion requesting recess and settlement conference, filed herein on May 3, 1962 is hereby denied.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP61-132

ORDER DENYING MOTION TO OMIT INTERMEDIATE DECISION PROCEDURE

(Issued May 17, 1962)

On April 12, 1962, Northern Natural Gas Company (Northern) filed a motion to omit the intermediate decision procedure herein.

Said motion recites that the Commission has twice passed upon this matter. In its order of October 20, 1961, denying Northern's motion for the waiver and omission of the intermediate decision, we determined that there was shown no reason to depart from the practice we had followed in other proceedings presenting complex issues such as are involved herein. In such cases we found it preferable to have an initial decision by the Presiding Examiner. In our order of November 30, 1961, we denied Northern's motion for reconsideration of the denial of waiver and omission. Northern alleges that four and one-half months have elapsed since the Commission's order of November 30, 1961, and since that date the Presiding Examiner has had the case before him ripe for decision.

Northern alleges that its offer of settlement involving a reduction of $1,000,000 in the effective zoned demand charges for contract demand and pipeline service rendered by Northern under its effective FPC Gas Tariff still stands. Northern asserts that this benefit as well as other benefits flowing from the authorization to make deliveries to the Bushton extraction plant of Northern Gas Products Company cannot and will not accrue unless Northern is issued a certificate in this proceeding.

Northern also incorporates the reasons set forth in its two original motions.

Telegraphic responses favorable to said motion have been received from Iowa Electric Light and Power Company, Iowa Illinois Gas and Electric Company, and Minnesota Valley Natural Gas Company, which latter company thereby accepts Northern's proposed settlement, without prejudice to Minnesota Valley's position in this matter.

Mid-America Pipeline Company (Mid-America) on April 20, 1962, filed a response urging the Commission to deny Northern's motion and asserting that the motion is filed untimely under the Commission's Rule 1.30(c)(3) which provides as follows:

> (3) Requests for waiver and omission of the intermediate decision procedure shall be by motion filed with the Commission at any time during, *but not later than five days next following, the conclusion or adjournment sine die of the hearing;* shall be in writing under oath, subscribed and verified; and shall in all other respects conform to the requirements of §§ 1.12 and 1.15 to 1.17, inclusive . . . (Emphasis supplied.)

Mid-America also alleges that Northern's third motion states no reasons which have not already been considered and rejected by the Commission. It alleges further that Northern's proposed $1,000,000 reduction in rates is merely an offset to the customers for the reduced Btu value of the gas which will be delivered to them, should the Commission grant Northern a certificate.

The Commission, having fully considered Northern's motion and the responses thereto, finds:

Northern's motion sets forth no new facts or reasons for omission of the intermediate decision procedure which have not been fully considered by the Commission when it issued the previous orders on Northern's two earlier motions. The public interest will be best served by having an intermediate decision by the Presiding Examiner. In addition, said motion is filed out of time.

The Commission orders:

The motion to omit intermediate decision procedure filed by Northern Natural Gas Company on April 12, 1962, be and the same is hereby denied.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

THE OHIO OIL COMPANY, OPERATOR, *ET AL.*, DOCKET NO. G–15385; SOUTHWEST NATURAL PRODUCTION COMPANY, DOCKET NOS. G–15460, G–19112; JAMES R. NOWERY AND B. M. NOWERY, JR., DOCKET NO. G–16190; NORMAN V. KINSEY, JR., *ET AL.*, DOCKET NO. G–16278; L. L. ROBINSON, *ET AL.*, DOCKET NO. G–16457; HUNT OIL COMPANY, DOCKET NO. G–16737; HASSIE HUNT TRUST, DOCKET NO. G–16763; MONSANTO CHEMICAL COMPANY, DOCKET NO. G–17519; THE ATLANTIC REFINING COMPANY, DOCKET NO. G–18572; T. L. JAMES & COMPANY, INC., DOCKET NO. G–19408; JACK W. GRIGSBY, OPERATOR, *ET AL.*, DOCKET NO. G–19705; ROBERT F. ROBERTS, DOCKET NO. G–19810

ORDER DENYING APPLICATIONS FOR REHEARING AND STAY

(Issued May 17, 1962)

Applications for rehearing of our order issued in the above-captioned consolidated proceeding on March 21, 1962, 27 FPC 551, have been filed under Section 19(b) of the Natural Gas Act (Act) and Section 1.34 of the Commission's Rules of Practice and Procedure by The Atlantic Refining Company in Docket No. G–18572 on April 20, 1962, and jointly by Hunt Oil Company and Hassie Hunt Trust in Docket Nos. G–16737 and G–16763, respectively, on April 19, 1962.

Among other things, our order issued permanent certificates of public convenience and necessity to said Applicants in Docket Nos. G–16737, G–16763, and G–18572, pursuant to Section 7(c) of the Act, authorizing the sale of natural gas from North Louisiana in interstate commerce by Applicants at 16.5 cents per Mcf at 15.025 psia, plus tax reimbursement of 1.75 cents per Mcf, to United Gas Pipeline Company for resale.

Applicants object to the attachment of the condition to our order which reduces the initial price in their gas sale contracts from 18.5 cents per Mcf. at 15.025 psia, exclusive of tax, to 16.5 cents per Mcf at 15.025 psia plus 1.75 cents tax reimbursement. The contentions of Applicants are not new, are without merit and should be denied. The application for rehearing filed by The Atlantic Refining Company includes an unsupported motion for a stay of the effectiveness of our order of March 21, 1962, insofar as it relates to that company. This motion should be denied.

The Commission finds:

(1) The assignments of error and grounds for rehearing relied upon by Applicants in their applications for rehearing set forth no new facts or principles of

law which were not fully considered by the Commission when it issued its order or which, having now been considered or reconsidered, warrant any change or modification of said order or of the terms and conditions set forth therein.

(2) The motion of The Atlantic Refining Company for a stay should be denied as hereinafter ordered.

The Commission orders:

The applications for rehearing filed by Applicants and the motion for a stay filed by the Atlantic Refining Company are hereby denied.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION, DOCKET NOS. CP61-328 AND CP62-86

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 17, 1962)

On June 19, 1961, as supplemented on June 19, 1961, and as amended on January 17 and February 26, 1962, Transcontinental Gas Pipe Line Corporation (Transco) filed in Docket No. CP61-328 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of approximately 120 (amended figure) miles of transmission purchase lateral pipelines; one 4,320 (amended figure) horsepower compressor station; and six purchase meter and regulator stations, with appurtenant equipment, for the purpose of receiving and transporting natural gas to be purchased by Transco from certain independent producers thereof in Blocks 129 and 131, Vermilion Area, Blocks 23 and 48, South Marsh Island Area, and Block 169, Ship Shoal Area, all offshore Louisiana, as more fully set forth in the application, as supplemented and amended.

The estimated total capital cost of the aforesaid facilities to be constructed by Transco under the application in Docket No. CP61-328 as amended, is $17,670,000.

Said proposed facilities are intended to connect additional sources of natural gas to augment Transco's system supply available to serve existing customers.

On October 2, 1961, as amended on February 5, 1962, Transco filed in Docket No. CP62-86 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of approximately 198 miles of main transmission line loop pipeline; 46,800 horsepower of compression in existing main line stations; 28 miles of loop pipeline and 2,000 horsepower of compression in an existing station on the Central Louisiana Gathering System; 26 miles of loop pipeline and 7,900 horsepower of compression on the Southeast Louisiana Gathering System; and 4,320 horsepower of compression in a proposed new station on the McMullen Gathering System; together with appurtenant facilities; all to be utilized for the purpose of rendering additional natural gas service of 102,127 Mcf per day to 32 existing customers of Transco, all as more fully set forth in the application, as amended.

The estimated total capital cost of the facilities proposed to be constructed by Transco under the application in Docket No. CP62-86, as amended is $54,000,000.

Transco proposes to finance the projects in the subject Docket Nos. CP61-328 and CP62-86 through the issuance of $80,000,000 of long-term securities, a portion of the proceeds of which is to be used to finance other facilities authorized by or pending before the Commission.

Temporary authorization to construct certain of the facilities proposed under the application in Docket No. CP61–328 has been granted by the Commission.

Pursuant to due notice, a public hearing was held in Washington, D.C. on May 10, 1962, respecting the matters involved in and the issues presented by the applications herein. A number of petitions to intervene and notices of intervention in either or both of the subject applications have been filed by various interested companies and State commissions, some of which have been supplemented or amended. In all cases, the burden of such filings has been that the petitioners did not request formal hearings in these proceedings and did not object to the hearing and disposition of the subject applications of Transco under the shortened procedure provided for by the Commission's Rules, but that each petitioner desired to preserve its rights to appear and participate fully in the event that these matters should be set for formal hearing. Inasmuch as the abridged hearing procedure is being used herein, no further action on the various intervention petitions appears necessary.

No protests to the granting of the applications having been received, and no other appearances having been entered at the hearing, staff counsel moved orally that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Transcontinental Gas Pipe Line Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of November 18, 1948, in Docket No. G–1143 (7 FPC 145).

(2) The facilities to be constructed by Transco, as hereinbefore described and as more fully described in the applications, as supplemented and amended, in Docket Nos. CP61–328 and CP62–86, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Transco's existing pipeline system and the construction and operation thereof by Transco are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Transco is able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities by Transco in Docket Nos. CP61–328 and CP62–86 are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificates issued hereinafter and the rights granted thereunder be conditioned upon Transco's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(1), (c)(3), (c)(4) and (e) of such regulations (except that paragraphs (a) and (c)(1) do not apply to the temporarily authorized portion of Docket No. CP61–328). Transco should be required to complete and place in actual operation the facilities hereinafter authorized in Docket No. CP62–86 within one year from the date on which this order issues, and the facilities hereinafter authorized in Docket No. CP61–328 within two years from the date on which this order issues.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Certificates of public convenience and necessity be and the same are hereby issued authorizing Transcontinental Gas Pipe Line Corporation to construct and operate the facilities hereinbefore described, all as more fully described in the respective applications, as supplemented and amended, in Docket Nos. CP61–328 and CP62–86, for the transportation and sale of natural gas in interstate commerce as therein set forth, upon the terms and conditions of this order.

(B) The certificates issued by paragraph (A) above and the rights granted thereunder are conditioned upon Transco's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(1), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations except that paragraph (a) and (c)(1) do not apply to the temporarily authorized portion of Docket No. CP61–328). Transco shall complete and place in actual operation the facilities hereinabove authorized in Docket No. CP62–86 within one year from the date on which this order issues, and the facilities hereinabove authorized in Docket No. CP61–328 within two years from the date on which this order issues.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

ALABAMA-TENNESSEE NATURAL GAS COMPANY, DOCKET NO. CP62–197

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 18, 1962)

On February 20, 1962, Alabama-Tennessee Natural Gas Company (Applicant) filed in Docket No. CP62–197 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the installation and operation of an additional 350 horsepower compressor unit on a standby basis in Applicant's Decatur Compressor Station in Limestone County, Alabama, all as more fully set forth in the application.

In the event of a breakdown of the existing compressor unit in the Decatur Compressor Station, the proposed facilities will insure continuity of service for those customers of Applicant located east of the compressor station.

No additional supply of natural gas is required and no increase in the peak day deliverability of Applicant's system is contemplated by the installation of the subject facilities.

The proposed facilities are estimated to cost $105,000, which will be financed from funds on hand or cash generated from internal sources.

Pursuant to due notice, a public hearing was held in Washington, D.C. on May 10, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Alabama-Tennessee Natural Gas Company, a Delaware corporation having its principal place of business in Florence, Alabama, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of July 2, 1948, in Docket NO. G–585 (7 FPC 257).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation and delivery of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsection (c) and (e) of Section 7 of the Natural Gas Act.

(3) The construction and operation of the facilities as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(4) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Alabama-Tennessee Natural Gas Company, to construct and operate the proposed facilities and to transport natural gas as hereinbefore described, all as more fully described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within four months from the date on which this order issues.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

EAST TENNESSEE NATURAL GAS COMPANY, DOCKET NO. CP62-177

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 18, 1962)

On February 2, 1962, East Tennessee Natural Gas Company (Applicant) filed in Docket No. CP62-177 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of approximately 1.21 miles of 2-inch lateral pipeline and a meter station in order to render natural gas service on an interruptible basis, from its existing 12-inch transmission line to Olin Mathieson Chemical

Corporation (Olin) for use in Olin's new plant near the City of Charleston, Tennessee.

Pursuant to a contract, dated January 1, 1962, between Applicant and Olin, Applicant will deliver up to 360 Mcf[1] of natural gas per day. The application shows Olin's estimated annual requirements to be 50,000 Mcf and 60,000 Mcf of natural gas during the first and second years of service, respectively, and 70,000 Mcf per year thereafter.

Olin will use natural gas as a fuel in the production of liquid chlorine. Applicant states that natural gas was selected as the major fuel because of its availability at a steady reliable pressure.

The estimated cost of the proposed facilities is $23,100, which cost will be financed from general operating funds.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 7, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, East Tennessee Natural Gas Company, a Tennessee corporation having its principal place of business in Knox County, Tennessee, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of May 3, 1949, in Docket No. G–1065 (8 FPC 836).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are to be used in the transportation and delivery of natural gas in interstate commerce, subject to the jurisdiction of the Commission and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities and the proposed transportation and delivery of natural gas by Applicant to Olin are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(1), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, East Tennessee Natural Gas Company, to construct and operate the proposed facilities and to transport and deliver to Olin Mathieson Chemical Corporation up to 360 Mcf of natural gas per day,

[1] At 14.9 psia and 1,000 BTU.

on an interruptible basis, as hereinbefore described, all as more fully described in the application herein, upon the terms and conditions of this order.

(B) The certificate issue by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(1), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(C) The facilities hereby authorized shall be constructed and placed in actual operation and the transportation and delivery of natural gas shall commence as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act within 3 months from the date on which this order issues.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

NATURAL GAS PIPELINE COMPANY OF AMERICA, DOCKET NO. CP62-121; UNITED GAS PIPE LINE COMPANY, DOCKET NO. CP62-134

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 18, 1962)

On November 14, 1961, as supplemented on January 16 and March 30, 1962, Natural Gas Pipeline Company of America (Natural) filed in Docket No. CP62-121 an application pursuant to Section 7(c) of the Natural Gas Act (Act) for a certificate of public convenience and necessity authorizing the construction and operation of certain additions to its transmission pipeline facilities in order to make increased deliveries of natural gas to nine existing customers for resale in existing market areas beginning during the 1962-1963 winter heating season, all as more fully set forth in the application, as supplemented.

The proposed new facilities consist of approximately 167 miles of 30-inch pipeline partially looping existing pipeline in Texas, Arkansas, Missouri and Illinois; approximately 57 miles of 36-inch pipeline partially looping existing pipeline in Kansas, Nebraska, Iowa and Illinois; approximately 1.40 miles of 16-inch lateral supply pipeline in Polk County, Texas; approximately 15 miles of 6-inch lateral supply pipeline in Jim Hogg and Zapata Counties, Texas; two new booster compressor stations in Polk County, Texas, and Stephens County, Oklahoma, with a total of 1,610 BHP installed; one new compressor station in Will County, Illinois, with 6,000 BHP installed; and the necessary measuring and other appurtenant facilities.

The subject proposal would increase Natural's system capacity by 94,500 Mcf per day, at an estimated total cost of $26,891,000, which would be financed through funds to be derived from the issuance and sale of bonds, with bank loans providing interim funds as needed.

On November 27, 1961, as supplemented on January 15, 1962, United Gas Pipe Line Company (United) filed in Docket No. CP62-134 an application pursuant to Section 7(c) of the Act for a certificate of public convenience and necessity authorizing the construction and operation of certain minor pipeline and metering facilities at United's Goodrich Compressor Station, Polk County, Texas, and the sale and delivery by means of said facilities of up to 50,000 Mcf of natural gas per day to Natural Gas Pipeline Company of America for resale. The estimated total cost of United's proposed facilities is $35,270, to be financed from current working funds, and the proposed sales would be made pursuant to United's presently effective filed FPC Gas Rate Schedule PL-C.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 10, 1962, respecting the matters involved in and the issues presented by the applications herein. The City of Chicago on February 19, 1962, filed a petition to intervene in Docket No. CP62–121, which petition was permitted to be withdrawn pursuant to request filed on March 16, 1962. No other petitions to intervene or protests to the granting of the respective applications have been received. Staff counsel moved orally at the hearing that the Commission render a decision herein pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Natural Gas Pipeline Company of America, a Delaware corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of October 13, 1942, in Docket No. G–235 (3 FPC 830).

(2) Applicant, United Gas Pipe Line Company, a Delaware corporation having its principal place of business in Shreveport, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of November 10, 1942, in Docket No. G–232 (3 FPC 863).

(3) The facilities to be constructed by Natural, as hereinbefore described and as more fully described in the application, as supplemented, in Docket No. CP62–121, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Natural's existing pipeline system and the construction and operation thereof by Natural are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The sale of natural gas by United to Natural, as hereinbefore described and as more fully described in the application, as supplemented, in Docket No. CP62–134, will be made for resale in interstate commerce, subject to the jurisdiction of the Commission, and such sale by United, together with the construction and operation of the facilities necessary therefor, is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) Natural and United, respectively, are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(6) The construction and operation of the facilities proposed by Natural in Docket No. CP62–121 and the sale and delivery of natural gas proposed by United in Docket No. CP62–134, together with the construction and operation by United of the facilities necessary therefor, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(7) Public convenience and necessity require that the certificates issued hereinafter and the rights granted thereunder be conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions (where applicable) set forth in paragraphs (a), (b), (c) (1), (c) (3), (c) (4) and (e) of Section 157.20 of such Regulations. Applicants should be required to complete and place in actual operation the facilities hereinafter authorized, as required by paragraph (b) aforesaid, by December 31, 1962.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Certificates of public convenience and necessity be and the same are hereby issued authorizing Natural Gas Pipeline Company of America and United Gas Pipe Line Company to construct and operate the facilities hereinbefore described, all as more fully described in the respective applications, as supplemented, in Docket Nos. CP62–121 and CP62–134, for the transportation and sale of natural gas in interstate commerce as therein set forth, upon the terms and conditions of this order.

(B) The certificates issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions (where applicable) set forth in paragraphs (a), (b), (c)(1), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations. Applicants shall have completed and placed in actual operation the facilities authorized by paragraph (A) above, and United shall commence the sale and delivery of natural gas to Natural, by December 31, 1962.

(C) The grant of the certificate to United in Docket No. CP62–134 shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or of Parts 154 and 157 of the Commission's Regulations thereunder requiring the filing of a rate schedule for the service hereinabove authorized, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against United. Further, our action in this proceeding shall not foreclose nor prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contract herein involved.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

TEXAS GAS TRANSMISSION CORPORATION, DOCKET NO. CP62–217

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 18, 1962)

On March 16, 1962, Texas Gas Transmission Corporation (Applicant) filed in Docket No. CP62–217 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction during the 12-month period commencing May 30, 1962, at a total cost not to exceed $3,000,000, with no single project to exceed a cost of $500,000, and the operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

Applicant proposes to finance the subject facilities from funds on hand.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 9, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission enter

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a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Texas Gas Transmission Corporation, a Delaware corporation having its principal place of business in Owensboro, Kentucky, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of March 30, 1949, in Docket No. G–859 (8 FPC 228).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas purchased from producers thereof as proposed by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit on or before July 31, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the actual final costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(6) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(7) The authorization hereinafter granted should be limited to construction during the 12-month period commencing May 30, 1962, and the total expenditures for facilities authorized to be constructed thereunder should be limited to $3,000,000, with no single project to exceed a cost of $500,000.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Texas Gas Transmission Corporation to construct during the 12-month period commencing May 30, 1962, the proposed facilities hereinbefore described, as more fully described in the application in this proceeding, and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Texas Gas Transmission Corporation.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general

terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(C) Applicant shall submit, on or before July 31, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the actual final costs of said project or projects, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the 12-month period commencing May 30, 1962, and the total expenditures for facilities to be constructed thereunder are hereby limited to $3,000,000, with no single project to exceed a cost of $500,000.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward

SOUTH TEXAS NATURAL GAS GATHERING COMPANY
DOCKET NO. CP62-206

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 18, 1962)

On February 28, 1962, South Texas Natural Gas Gathering Company (Applicant) filed in Docket No. CP62-206 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction during the calendar year 1962, at a total cost not to exceed $500,000, with no single project to exceed a cost of $50,000, and the operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

Applicant proposes to finance the subject facilities from funds on hand, from cash generated by operations, and from internal sources.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 9, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, South Texas Natural Gas Gathering Company, a Texas corporation having its principal place of business in Corpus Christi, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of December 1, 1959, in Docket No. G-17050 (22 FPC 979).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of

natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas purchased from producers thereof as proposed by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the actual final costs of the facilities so constructed, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(6) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(7) The authorization hereinafter granted should be limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed thereunder should be limited to $500,000, with no single project to exceed a cost of $50,000.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, South Texas Natural Gas Gathering Company, to construct during the calendar year 1962 the proposed facilities hereinbefore described, as more fully described in the application in this proceeding, and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to South Texas Natural Gas Gathering Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(C) Applicant shall submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects constructed pursuant to the authorization granted in paragraph (A) above, (d) the location of said project or projects, (e) the actual final costs of said project or projects, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(d) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities, to be constructed thereunder are hereby limited to $500,000, with no single project to exceed a cost of $50,000.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

UNITED GAS PIPE LINE COMPANY, DOCKET NO. CP62-95

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 18, 1962)

On October 12, 1961, as supplemented on January 18, 1962, United Gas Pipe Line Company (Applicant) filed in Docket No. CP62-95 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of a side tap, positive sales meter station, 0.0047 miles of 2-inch pipeline, and appurtenant facilities on its 16-inch Latex-Beaumount pipeline in Shelby County, Texas, and the sale and delivery of natural gas to Farmers Natural Gas Company (Farmers) for resale and distribution in and about Shelbyville, Texas, all as more fully set forth in the application, as supplemented.

Farmers estimates the gas requirements of Shelbyville as follows:

	Volumes in Mcf	
	1st year	3d year
Annual requirements	11,951	13,619
Peak day requirements	161	169

Farmers proposes to construct and operate the necessary distribution system in Shelbyville, a regular station, and approximately 5.5 miles of 2-inch pipeline to connect the distribution system to Applicant's main line. The estimated cost of Farmers' proposed project is $44,950.

The cost of the facilities which Applicant proposes to construct is estimated to be $2,851, to be financed from current working funds. The service to Farmers will be rendered under Applicant's presently effective rates on file with the Commission.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 10, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, United Gas Pipe Line Company, a Delaware corporation having its principal place of business in Shreveport, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of January 20, 1942, in Docket No. G-216 (3 FPC 2).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof and the proposed sale and delivery of natural gas by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The proposed construction and operation of facilities and the proposed sale of natural gas to Farmers Natural Gas Company for resale by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, United Gas Pipe Line Company, to construct and operate the facilities and to sell and deliver natural gas to Farmers Natural Gas Company for resale, as hereinbefore described, all as more fully described in the application, as supplemented in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of such Regulations.

(C) The time within which the facilities hereby authorized shall be constructed and placed in actual operations as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act is hereby fixed at six months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, Charles R. Ross and Harold C. Woodward.

GULF STATES UTILITIES COMPANY, DOCKET NO. E-7030

SUPPLEMENTAL ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTGAGE BONDS

(Issued May 21, 1962)

By order issued May 4, 1962, supra p. 902, in the above-entitled matter, the Commission authorized Gulf States Utilities Company (Applicant) to issue and sell at competitive bidding $17,000,000, principal amount of First Mortgage Bonds, due 1992, subject, among others, to the provisions set forth in paragraph (B) of that order, as follows:

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

Applicant, on May 21, 1962, filed an amendment, pursuant to the requirements of the afore-mentioned Commission order, in which it states that it proposes to accept, as representing the lowest annual cost of money to it, the joint bid of Salomon Brothers & Hutzler and Eastman Dillon, Union Securities & Co. to purchase the proposed issuance of Bonds at the price of 100.78% of principal amount, with an interest rate of 4⅝% per annum.

The Commission finds:

(1) Applicant has satisfactorily complied with the requirements of pargraph (B) of the Commission's order issued May 4, 1962, in the above docket, and under the bid it proposes to accept for the Bonds, the price to be received by Applicant therefor and the interest rate thereof are reasonable.

(2) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably appropriate for such purposes.

The Commission orders:

(A) The price to be received by Applicant for the proposed Bonds and the interest rate thereof under the bid referred to above are approved as reasonable.

(B) The proposed issuance and sale of Bonds referred to above, upon the terms and conditions and for the purposes specified in the application, as supplemented by the amendment referred to above, are hereby authorized subject only to the provisions of paragraphs (A, (C), (D), and (E) of the Commission's order issued May 4, 1962 in the above docket.

Before Commissioner: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

NORTHERN NATURAL GAS COMPANY, *ET AL.*, DOCKET NO. G–17485, *ET AL.*; CITY OF GUTTENBERG, *ET AL. v.* NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP62–140

ORDER GRANTING PETITION FOR MODIFICATION OF ORDER AND INDICATING SATISFACTION OR DISMISSAL OF COMPLAINTS

(Issued May 21, 1962)

On March 8, 1962, Northern Natural Gas Company (Northern), a Delaware corporation with principal place of business at 2223 Dodge Street, Omaha 1,

Nebraska, filed a "Petition for Modification of Order" issued November 1, 1961, in the above-entitled proceeding, 26 FPC 672, which had amended the order accompanying Opinion No. 324, issued July 31, 1959, 22 FPC 164, as amended August 26, 1960, 24 FPC 341. This petition requested that Northern be reauthorized to construct certain branch-line facilities which the order of November 1, 1961, had deleted from the certificate originally issued to Northern by the order accompanying Opinion No. 324.

At Northern's request, the order of November 1, 1961, *inter alia*, had deleted Northern's authorization to construct and operate the branch-line facilities required to initiate natural-gas service to the communities of Guttenberg, Clermont, Elgin, Elkader, and Lansing, Iowa. After the issuance of the aforesaid order of November 1, 1961, the City of Guttenberg, Iowa, and the Towns of Clermont, Elgin, Elkader, and Lansing,[1] Iowa,[2] filed on December 1, 1961, a "Joint Notice of Intervention", "Joint Application for Reconsideration, Modification, or Rehearing" in Docket Nos. G–17485, *et al.*, and a "Joint Complaint" in Docket No. CP62–140[3] in which they alleged, among other things, that they did not receive proper notice of Northern's intention to request that authorization to construct the facilities required to serve them be deleted from the certificate originally issued to Northern by the order acompanying Opinion No. 324. These Interveners also claimed that they were still feasible for natural-gas service. By order issued herein on December 22, 1961, 26 FPC 922, the Commission granted intervention and rehearing "* * * subject to the further action which will be required upon receipt and evaluation of Northern's answer to the Interveners' complaint".

On March 8 Northern and the Interveners jointly filed a document entitled "Satisfaction and Notice of Withdrawals of Complaint" in which they stated on page 3 thereof:

> * * * various discussions and negotiations have been conducted with representatives of all parties respecting the economic feasibility of providing gas service to these * * * Iowa communities. These meetings have resulted in a determination that natural gas service is economically feasible and desirable in the communities of Guttenberg and Elkader but that such service is not presently feasible for the communities of Elgin * * * [and Clermont].

The joint "Satisfaction and Notice" then states that if the Commission grants Northern's petition mentioned in the first paragraph of this order, requesting that it be reauthorized to construct and operate the branch-line facilities necessary to render natural-gas service to Guttenberg and Elkader, that the Interveners' complaints in Docket Nos. CP62–140 and IN–949 should "* * * be ordered satisfied as respects the communities of Guttenberg and Elkader and withdrawn without prejudice as respects the communities of Elgin [and Clermont]".

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[1] On March 12, 1962, the Commission received a letter from Mr. William S. Hart, Jr., Attorney for the Town of Lansing, notifying the Commission that the Town of Lansing had been inadvertently included in the filings by the City of Guttenberg, *et al.*, and requesting that Lansing be allowed to remain "* * * in the same position it would have been in if no Appeal were ever taken from the Commission Order of November 1, 1961". Since the Town of Lansing seems to have been mistakenly included in these filings, no further mention will be made of Lansing in this order and the exclusion of Lansing from the Commission's considerations herein will necessarily culminate in the result requested by its attorney.

[2] The four communities of Guttenberg, Clermont, Elgin, and Elkader will hereinafter be referred to as "Interveners".

[3] Interveners had also filed on November 30, 1961, an informal complaint in Docket No. IN–949.

Northern's petition furnishes information regarding the miles of 4-inch and 3-inch branch lines and other facilities required to initiate natural-gas service to Guttenberg and Elkader, as well as an estimate of the costs associated with the construction of the requisite facilities.

Paragraph (C) of the Commission's order issued August 26, 1960, 24 FPC 341, amended the order accompanying Opinion No. 324 so as to extend the time within which Northern was required to construct all branch-line facilities authorized in Docket Nos. G–17485, *et al.* to and including October 31, 1961. Northern's petition herein requests that this provision, regarding the time within which facilities must be constructed, be extended to and including October 27, 1962, so as to permit Northern sufficient time to construct and place into operation the branch-line facilities required to serve Guttenberg and Elkader.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that:

(1) Northern's petition for modification of the order issued November 1, 1961, in Docket Nos. G–17485, *et al.*, and its request that extension of time within which to construct branch-line facilities as provided for in the order of August 26, 1960, issued in Docket Nos. G–17485, *et al.*, be granted.

(2) Interveners' informal complaint filed November 30, 1961, in Docket No. IN 949 and formal complaint filed December 1, 1961, in Docket No. CP62–140 should be ordered satisfied as to Guttenberg and Elkader and dismissed without prejudice as to Elgin and Clermont inasmuch as the action taken herein grants the relief requested by Interveners.

The Commission orders:

(A) Paragraph (A) of the Commission's order issued November 1, 1961, 26 FPC 672, amending the order accompanying Opinion No. 324 issued July 31, 1959, 22 FPC 164, 179, as amended August 26, 1960, 24 FPC 341, is hereby further amended so as to reauthorize Northern to construct and operate the branch-line facilities necessary to initiate natural-gas service to Guttenberg and Elkader, Iowa, as requested and described in Northern's "Petition for Modification of Order" filed March 8, 1962, in Docket Nos. G–17485, *et al.*

(B) Paragraph (C) of the Commission's order issued August 26, 1960, 24 FPC 341, 348, is hereby amended so as to extend the time within which Northern shall construct the branch-line facilities reauthorized herein to and including October 27, 1962.

(C) The complaints filed by The City of Guttenberg and the Towns of Clermont, Elgin, and Elkader in Docket No. IN 949 on November 30, 1961, and in Docket No. CP62–140 on December 1, 1961, are hereby considered satisfied as to Guttenberg and Elkader, Iowa, and dismissed without prejudice as to Elgin and Clermont, Iowa.

(D) All other provisions of the Commission's orders issued August 26, 1960, 24 FPC 341, and November 1, 1961, 26 FPC 672, shall remain unchanged.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

AMENDMENT OF PART 45 OF REGULATIONS UNDER THE FEDERAL POWER ACT—PRESCRIBING THE FORM FOR INTERLOCKING DIRECTORATE APPLICATIONS, DOCKET NO. R–208

ORDER NO. 246

ORDER PRESCRIBING REVISED FORM

(Issued May 21, 1962)*

The Commission has under consideration in this proceeding the amendment of Part 45 of its Regulations under the Federal Power Act by revising section 45.8 thereof entitled "Contents of Application" to read as set forth in the attachment hereto. The section prescribes the basic information which is to be submitted in support of applications for authorization, pursuant to section 305(b) of the Federal Power Act, to hold the positions of officer or director of more than one public utility, or of a public utility and a firm authorized to underwrite or participate in the marketing of public utility securities, or of a public utility and a firm engaged in supplying electrical equipment to such public utility.

The amendments herein adopted are designed to delete subsections requiring the submission of information already on file with or readily available to the Commission and to simplify the format in which the required information must be submitted, encouraging the use of tables and eliminating the necessity for repetition of information applicable to more than one corporation or firm. The adoption of the amendments will result in a substantial reduction in the time and effort required to prepare applications filed in the future and in a reduction in size of most applications by approximately 50 percent, particularly when a holding company system is involved.

General public notice of the proposed rulemaking was given by publication of notice in the Federal Register, on March 10, 1962 (27 F.R. 2325), and by mailing copies thereof to interested persons, including public utilities, and to State and Federal agencies. Several comments were received—all of them favoring the proposed revision. Pennsylvania Power & Light Company further suggested the adoption of a procedure which would provide for automatic approval by the Commission of interlocking directorates which fall within certain prescribed categories. We are of the opinion that a procedure for automatic approval of positions in interlocking directorates is not contemplated by section 305(b) of the Act, since it requires that the granting of such authorization shall be by order of the Commission only upon due showing that neither public nor private interests will be adversely affected. New England Power Service Company suggested that Item (a)(3) require the applicant to make reference only to the last application filed, rather than to all previous applications. We are changing Item (a)(3) accordingly, and, with that exception, adopting the revision as originally proposed in the notice.

The Commission finds:

Adoption and promulgation of the proposed amendments are necessary and appropriate for the purposes of administration of the Federal Power Act.

The Commission, acting pursuant to authority granted by the Federal Power Act, as amended, and particularly sections 305(b) and 309 thereof (16 U.S.C. 825d, 825h), *orders:*

*Published in Federal Register on May 25, 1962 (27 F.R. 4911).

(A) Section 45.8 entitled "Contents of application", of the Commission's Regulations under the Federal Power Act (18 CFR 45.8) is hereby amended to read as set forth in the attachment hereto.

(B) These amendments to the Commission's Regulations under the Federal Power Act, shall become effective June 20, 1962.

(C) The Secretary of the Commission shall cause prompt publication of this order to be made in the Federal Register.

ATTACHMENT

45.8 *Contents of application*

Each application shall state the following:

(a) *Identification of applicant.* (1) Full name, business address, and place of residence.

(2) Major business or professional activity.

(3) If former application or applications under section 305(b) of the Act have been made by the applicant, give date and docket number of the last application filed.

(4) If application is not filed with the Commission within 30 days after election or appointment, state reasons in full for the delay.

(b) *List of positions within the purview of section 305(b) of the act for which authorization is sought.* (Indicate by asterisk positions which were the subjects of previous authorizations.)

Position	Name of Corporation	Classification
		(1) Public utility, (2) authorized by law to underwrite, (3) supplying electrical equipment.

(c) *Data as to positions with each public utility mentioned in paragraph* (b) *of this section.* (The format should be adapted to the information submitted, in keeping with completeness and conciseness. In the case of public utilities of the same holding company system, brevity will generally be promoted by submitting the information for all of the utilities involved under each subsection progressively in the order of the subsections, utilizing tables when feasible.)

(1) Name, principal place of business, and a brief description of operations.

(2) Date elected or appointed, or anticipated date of election or appointment, to each position not previously authorized.

(3) Names of officers and directors; number of vacancies, if any, on Board of Directors.

(4) Description of applicant's duties: approximate amount of time devoted thereto; and, if applicant seeks authorization as a director, when and where directors meetings have been held during the past 12 months and number of such meetings attended by applicant.

(5) All other professional, contractual, or business relationships of applicant with the public utility, either directly or through other corporations or firms.

(6) Extent of applicant's direct or indirect ownership, control of, or beneficial interest in the public utility or the securities thereof. If ownership or interest is held in a name other than that of applicant, state name and address of the holder.

(7) Extent of applicant's indebtedness to the public utility, how and when incurred, and consideration therefor.

(8) All money or property received by applicant from the public utility or any affiliate during the past 12 months, and expected during the ensuing 12 months, whether for services, reimbursement of expenses, or otherwise. Specify in detail the amount thereof and the basis therefor. If applicant's compensation for services to the public utility is not paid directly by the public utility, give name of the corporation which does pay same, the amount allocated or allocable to the public utility or any affiliate, and the basis or reason for such allocation.

(9) Name and address of principal place of business of any corporation which renders management, construction or other service to the public utility pursuant to contract or other continuing arrangement.

(10) Whether during the past five years the public utility or any affiliate thereof or any security holders of either have commenced any suit against the officers or directors thereof for alleged waste, mismanagement or violation of duty, to which suit applicant was a party defendant. If so, give date of commencement of suit, court in which commenced, and present status.

(11) Whether the public utility or any affiliate thereof, during the past five years and while applicant held a position therein, has either voluntarily or involuntarily been the subject of any proceeding in bankruptcy (including 77(b), 48 Stat. 912; 11 U.S.C. 207), insolvency or equity receivership, either Federal or State. If so, give date of commencement of proceeding, court in which commenced, and present status.

(d) *Data as to positions with each bank, trust company, banking association or firm, mentioned in paragraph (b) of this section, that is authorized by law to underwrite or participate in the marketing of securities of a public utility.* (The applicant shall use a separate sheet for each corporation).

(1) Name of corporation, State and date of incorporation (if any) and address of principal place of business.

(2) States in which corporation is doing business or has qualified to do business.

(3) Positions which applicant holds or seeks authorization to hold therein and when and by whom elected or appointed to each position.

(4) Description of applicant's duties in each position and approximate amount of time devoted thereto, and, if applicant seeks authorization as director, where directors meetings are held.

(5) Extent of applicant's direct or indirect ownership, or control of, or beneficial interest in, the company or in the securities thereof, including common stock, preferred stock, bonds, or other securities. If such ownership or interest is held in a name other than that of applicant, state name and address of such holder.

(6) All money or property received by applicant from the company during the past 12 months, and expected during the ensuing 12 months whether for services, reimbursement for expenses, or otherwise. Specify in detail the amount thereof and the basis therefor.

(7) Names, titles, and residence addresses of directors, officers, or partners.

(8) Whether the corporation is now engaged in underwriting or participating in the marketing of the securities of a public utility; if so, to what extent.

(9) Whether the corporation, during applicant's connection therewith, has underwritten or participated in the marketing of the security issue of any public utility with which applicant was also connected; if so, the details with respect to every such transaction.

(10) (If the answer to subparagraph (8) of this paragraph is in the negative) Give excerpts from the charter, declaration of trust, or articles of partnership which authorize the underwriting or participating in the marketing of securities of a public utility.

(11) (If the answer to subparagraph (8) of this paragraph is in the negative) Give general requirements of and appropriate reference to, the laws of the State of organization and of States in which corporation is doing business or has qualified to do business, with which it must comply in order to engage in the business of underwriting or participating in the marketing of the securities of a public utility.

(12) What steps, if any, have been taken to comply with laws mentioned in subparagraph (11) of this paragraph.

(13) In lieu of subparagraphs (10), (11), and (12) of this paragraph, an opinion by counsel to the same effect and including the information in respect thereto may be filed with the application.

(14) Whether the corporation has registered with the Securities and Exchange Commission; if so, when and under what section of what act.

(e) *Data as to positions with each company, mentioned in paragraph (b) of this section, supplying electrical equipment to a public utility in which applicant holds a position. (Applicant shall use a separate sheet for each company.)*

(1) Name of company, State and date of incorporation (if any), and address of principal place of business.

(2) Positions which applicant holds or seeks authorization to hold therein and when and by whom elected or appointed to each position.

(3) Description of applicant's duties in each position and approximate amount of time devoted thereto, and, if applicant seeks authorization as director, when and where directors meeting have been held during the past 12 months and number of said meetings attended by applicant.

(4) Names, titles, and residence addresses of directors or partners.

(5) Name of each public utility, with which applicant holds or seeks authorization to hold a position, to which the company supplies electrical equipment; the frequency of such transactions; the approximate annual dollar volume of such business; and the type of equipment supplied.

(6) Nature of relationship between the company supplying electrical equipment and the public utility:

(i) Whether company manufactures such electrical equipment or is a dealer therein.

(ii) Whether company supplies electrical equipment to the public utility pursuant to construction, service, agency, or other contract with the public utility or an affiliate thereof, and, if so, furnish brief summary of the terms of such contract.

(7) Extent of applicant's direct or indirect ownership, or control of, or beneficial interest in, the company or in the securities thereof, including common stock, preferred stock, bonds, or other securities. If such ownership or interest is held in a name other than that of applicant, state name and address of such holder.

(8) All money or property received by applicant from the company during the past 12 months, and expected during the ensuing 12 months whether for services, reimbursement for expenses, or otherwise. Specify in detail the amount thereof and the basis therefor.

(f) *Data as to positions with public utility holding companies.* (Do not include here data as to corporations listed in paragraph (b) of this section which are also holding companies. A "holding company" as herein used means any corporation which directly or indirectly owns, controls, or holds with power to vote, ten per centum or more, of the outstanding voting securities of a public utility.)

(1) Name of holding company, State and date of incorporation (if any), and address of principal place of business.

(2) Positions which applicant holds therein, when and by whom elected or appointed to each position.

(3) Extent of applicant's direct or indirect ownership, or control of, or beneficial interest in, the holding company or in the securities thereof, including common stock, preferred stock, bonds, or other securities. If such ownership or interest is held in a name other than that of applicant, state name and address of such holder.

(4) All money or property received by applicant from the holding company during the past 12 months, and expected during the ensuing 12 months, whether for services, reimbursement for expenses, or otherwise. Specify in detail the amount thereof and the basis therefor.

(g) *Positions with all other corporations.* (Do not include here data as to any corporations listed in paragraphs (b) or (f) of this section.)

(1) All other corporations and positions therein, including briefly the information required in parellel columns as below:

Name of Corporation	Address: Kind of business	Position held therein

(2) Any corporate, contractual, financial, or business relationships between any of the corporations listed in subparagraph (1) of this paragraph and any of the public utilities listed in paragraph (b) of this section.

(h) *Data as to the public utility holding company system.* The names of the public utility holding company systems of which each public utility listed in paragraph (b) of this section is a part, with a chart showing the corporate relationships existing between and among the corporations within the holding company systems.

[Authority: Secs. 305(b), 309, 49 Stat. 856, 858; 16 U.S.C. 825d(b), 825h]

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

TEXAS EASTERN TRANSMISSION CORPORATION AND WILLIAM E. SNEE, ORVILLE EBERLY, ROBERT E. EBERLY & L. N. MURRAY, DOCKET NO. CP62-44

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND PERMITTING AND APPROVING ABANDONMENT

(Issued May 21, 1962)

On August 21, 1961, as supplemented on December 18, 1961,[1] Texas Eastern Transmission Corporation (Texas Eastern) and William E. Snee, Orville Eberly, Robert E. Eberly and L. N. Murray (Snee, *et al.*) (sometimes hereinafter referred to jointly as Applicants) filed pursuant to Section 7 of the Natural Gas Act a joint application for: (a) permission and approval for the abandonment by Snee, *et al.*, of the sale of natural gas to Cumberland and Allegheny Gas Company (C&A) from Accident Field, Garrett County, Maryland; (b) a certificate

[1] On March 29, 1962, Applicants filed a second supplement further extending the time specified between Applicants for obtaining necessary governmental authorizations.

of public convenience and necessity authorizing Texas Eastern to acquire by purchase from Snee, *et al.*, the latter's leasehold interests, together with appurtenant facilities, in the Accident Field; and (c) a certificate of public convenience and necessity authorizing the sale by Texas Eastern to C & A of up to 4,000,000 Mcf per year of natural gas from the Accident Field for a period ending May 1, 1964.

Snee, *et al.*, presently sell gas from the Accident Field to C & A under contracts, dated September 14, 1953, and November 26, 1954, which sales were authorized by the Commission's orders issued September 28, 1956, in Docket No. G–7682, and May 6, 1955, in Docket No. G–8381. The application shows that Texas Eastern desires to acquire the Accident Field for ultimate development as a gas storage field, which project will be the subject of a future application. Upon the consummation of the subject acquisition, Snee, *et al.*, will abandon the sale of gas to C & A from the subject's field, and Texas Eastern will commence the sale of natural gas to C & A in the same volumes and at the same price (27.5 cents per Mcf) as provided in the contracts between C & A and Snee, *et al.*, for a period ending May 1, 1964. The maximum deliveries are to be no more than 4,000,000 Mcf per year. Texas Eastern and C & A have entered into an agreement for such service on such terms.

C & A states that it has agreed to such arrangement because it anticipates the development of other gas supply in acreage bordering the Accident Field and from other nearby sources.

Texas Eastern will pay $11,006,000 as of January 1, 1961, for the interest of Snee, *et al.*, in the Accident Field; this price will be reduced by an amount equivalent to the value of the gas sold to C & A between January 1, 1961, and the date of consummation of the subject transaction. Texas Eastern will finance the cost from cash on hand or from proceeds secured under revolving credit agreements with certain banks.

The application shows an estimated sum of $8,058,262 for "depletion of gas reserves" which sum represents the adjusted purchase price less depreciated original cost of the properties to Snee, *et al.*, as of January 1, 1961. Texas Eastern will charge this amount to account 114, Gas Plant Acquisition Adjustment. The certificate hereinafter issued to Texas Eastern should be conditioned upon Texas Eastern charging the amortization of the acquisition adjustment to account 425, miscellaneous amortization, based on the proposed maximum annual sale of 4,000,000 Mcf to C & A. Further, Texas Eastern should not include the Accident Field transaction in any rate proceeding before the Commission prior to May 1, 1964, and, at the time Texas Eastern files for authorization to utilize Accident Field as a storage project, it should indicate, to the satisfaction of the Commission, its plan for disposition of the then remaining balance in account 114.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 10, 1962, respecting the matters involved in and the issues presented by the joint application, as supplemented, herein. On April 30, 1962, The Brooklyn Union Gas Company filed a petition requesting intervention in the event the subject proceeding should not be disposed of pursuant to the abridged hearing procedure. Since the subject proceeding is being disposed of pursuant to the provisions of Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure, no further action on the intervention petition of The Brooklyn Union Gas Company appears necessary. No appearance other than that of staff counsel was entered at the hearing. No other petitions to intervene or protests to the granting of the joint application having been received, staff counsel moved orally at the hearing that the intermediate decision procedure

be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Texas Eastern Transmission Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of October 10, 1947, in Docket No. G-880 (6 FPC 148).

(2) Applicants, Snee, *et al.*, independent producers of natural gas, are engaged in the sale of natural gas in interstate commerce for ultimate public consumption, subject to the jurisdiction of the Commission, and each is, therefore, a "natural-gas company" within the meaning of the Natural Gas Act.

(3) The leasehold interests, together with appurtenant facilities, to be acquired by Texas Eastern from Snee, *et al.*, are subject to the jurisdiction of the Commission, and the acquisition and operation thereof by Texas Eastern are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The sale of natural gas by Texas Eastern to C & A hereinbefore described, as more fully described in the joint application, as supplemented, in this proceeding, will be made in interstate commerce subject to the jurisdiction of the Commission, and such sale by Texas Eastern, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefore, is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) The acquisition of the subject leasehold interests, together with appurtenant facilities, and the sale of natural gas by Texas Eastern to C & A, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are all required by the public convenience and necessity, and certificates therefor should be issued as hereinafter ordered and conditioned.

(6) The sale of natural gas proposed to be abandoned by Snee, *et al.*, as hereinbefore described and as more fully described in the joint application, as supplemented, in this proceeding, is subject to the jurisdiction of the Commission, and abandonment of said sale by Applicant is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(7) Such abandonment by Snee *et al.*, as heretofore described, is permitted by the public convenience and necessity, and an order authorizing and approving same should be issued as hereinafter ordered.

(8) Applicants are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(9) Public convenience and necessity require that the certificate issued hereinafter authorizing the proposed acquisition and the rights granted thereunder be conditioned upon Texas Eastern's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (d) and (e) of Section 157.20 of such Regulations.

(10) The certificate hereinafter issued to Texas Eastern should be conditioned upon:

(a) Texas Eastern charging the amortization of the acquisition adjustment to account 425, miscellaneous amortization, based on the proposed maximum annual sale of 4,000,000 Mcf to C & A;

(b) Texas Eastern not including the Accident Field transaction in any rate proceeding before the Commission prior to May 1, 1964; and

(c) Texas Eastern indicating, to the satisfaction of the Commission, at the time it files for authorization to utilize Accident Field as a storage project, its plan for disposition of the remaining balance in account 114.

(11) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Texas Eastern to acquire from Snee, *et al.*, and operate the latter's leasehold interests in the Accident Field, together with appurtenant facilities, as hereinbefore described, all as more fully described in the joint application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) A certificate of public convenience and necessity be and the same is hereby issued, upon the terms and conditions of this order, authorizing the sale by Texas Eastern of natural gas to C & A in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary for such sale, as hereinbefore described, all as more fully described in the joint application, as supplemented, in this proceeding.

(C) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Texas Eastern's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (d) and (e) of Section 157.20 of such Regulations.

(D) The certificate issued to Texas Eastern by paragraph (A) above is hereby conditioned upon:

(a) Texas Eastern charging the amortization of the acquisition adjustment to account 425, miscellaneous amortization, based on the proposed maximum annual sale of 4,000,000 Mcf to C & A;

(b) Texas Eastern not including the Accident Field transaction in any rate proceeding before the Commission prior to May 1, 1964; and

(c) Texas Eastern indicating, to the satisfaction of the Commission, at the time it files for authorization to utilize Accident Field as a storage project, its plan for disposition of the remaining balance in account 114.

(E) The acquisition hereinabove authorized shall be consummated and operation begun by Texas Eastern within 3 months of the date hereof.

(F) The certificate granted in paragraph (B) above is not transferable and shall be effective only so long as Texas Eastern continues the operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations and orders of the Commission.

(G) The grant of the certificate issued in paragraph (B) above shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or Part 154 or Part 157 of the Commission's Regulations thereunder, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Applicant. Further, our action in this proceeding shall not foreclose or prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas sale contract herein involved.

(H) Permission for and approval of the abandonment by Snee, *et al.*, of the

sale of natural gas, as hereinbefore described and as more fully described in the joint application, as supplemented, in this proceeding, be and the same is hereby granted.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

UNION TEXAS PETROLEUM, A DIVISION OF ALLIED CHEMICAL CORPORATION (FORMERLY UNION TEXAS NATURAL GAS CORPORATION), DOCKET NOS. G–15833 AND G–16023

ORDER GRANTING EXTENSION OF TIME

(Issued May 22, 1962)

By its order issued March 5, 1962, in Texaco Inc., et al., Docket Nos. G–15546, *et al.*, 27 FPC 441, the Commission disposed of more than 400 proceedings, including those above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. With respect to the above-listed dockets, ordering paragraph (A) of the March 5 order directed Union Texas Petroleum, a Division of Allied Chemical Corporation (formerly Union Texas Natural Gas Corporation and hereinafter referred to as Union Texas) to refund tax-reimbursement amounts collected from its direct customer Texas Gas Transmission Corporation (Texas Gas). Ordering paragraph (C) of that order directed that within 90 days from the date of issuance thereof, Union Texas report to the Commission the details of its refund calculations and submit a copy of a release from Texas Gas respect to the required refunds. By order issued April 26, 1962 in *Texaco Inc. et al.*, Docket No. G–15546, *et al.*, the Commission denied applications for rehearing of the March 5 order in the above, as well as other, dockets. On May 15, 1962, Union Texas filed a motion seeking to stay the effectiveness of the March 5 order, insofar as applicable to the above dockets, until a date 30 days after the conclusion of judicial review of said order in those dockets. The motion recies that Union Texas intends promptly to seek judicial review of the March 5 order and that failure of the Commission to grant the stay pending such review would cause irreparable injury to Union Texas.

For reasons stated in our order of April 13, 1962[1] granting Pan American Petroleum Corporation an extension of time for compliance, we are disposed to extend the time within which Union Texas must comply with ordering paragraphs (A) and (C) of the Commission's March 5 order, for a period ending 30 days after the conclusion of judicial review of that order in the instant dockets.[2] The extension is conditional, however, upon the payment by Union Texas to Texas Gas of interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the order of March 5.

The Commission finds:

(1) There is good cause for extending the time within which Union Texas must comply with the requirement of ordering paragraphs (A) and (C) of our

[1] Pan American Petroleum Corporation, Docket No. G–15641, Pan American Petroleum Corporation (Operator), *et al.*, Docket No. G–15650, G–15780.

[2] It should be understood that the 30th day after judicial review in the above dockets is the date upon which Union Texas must comply with the March 5 order; it is *not* the date upon which the 90-day period referred to in ordering paragraph (C) of the March 5 order commences to run.

order of March 5, 1962, for a period ending 30 days after the conclusion of judicial review of that order in the instant dockets.

(2) It is just and reasonable and in the public interest that Union Texas be required to pay Texas Gas interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after the issuance of the March 5 order.

The Commission orders:

(A) The time within which Union Texas must comply with ordering paragraphs (A) and (C) of the Commission's order of March 5, 1962 is extended for a period ending 30 days after the conclusion of judicial review of the Commission's order of March 5, 1962 in the instant dockets.

(B) Union Texas shall pay Texas Gas interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the March 5, 1962 order. The time within which Texas Gas must comply with ordering paragraphs (B) and (D) of the March 5, 1962 order, insofar as applicable to the instant dockets, is extended for a period ending 60 days after conclusion of judicial review of that order in said dockets.

(C) The preceding paragraphs (A) and (B) hereof shall not be deemed operative unless and until Union Texas shall have petitioned for review in the instant dockets. Thus, if within 90 days after the issuance of the March 5 order, Union Texas shall neither have complied with ordering paragraphs (A) and (C) thereof nor petitioned for review, it shall be deemed in default.

By the Commission.

JOSEPH H. GUTRIDE,
Secretary.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

GORDON STREET, INC., DOCKET NO. G–17722

ORDER ACCEPTING OFFER OF SETTLEMENT AND TERMINATING PROCEEDING

(Issued May 23, 1962)

On May 1, 1962, Gordon Street, Inc. (Street) filed an Offer of Settlement of the suspension proceeding in Docket No. G–17722 involving its jurisdictional sale of natural gas to Tennessee Gas Transmission Company (Tennessee Gas) in the Lick Branch Field, Liberty County, Texas (Railroad Commission District No. 3). In the offer, Street proposes to reduce the increased rate of 16.16947 cents per Mcf, which is suspended herein and has not been made effective, to a settlement rate of 14.6 cents per Mcf at 14.65 psia.

Under the terms of the offer, the favored-nation and price redetermination provisions are to be eliminated from the rate schedule involved [1] and the tax reimbursement clause therein is to be revised to provide for reimbursement of three-fourths of any increase in tax levied after January 1, 1959. In addition, Street proposes that the 14.6 cent per Mcf settlement rate be effective from the date of Commission authorization until January 1, 1964 with a 1 cent per Mcf escalation then and thereafter on January 1, 1969.

In support of its offer, Street states, among other things, that it is willing to take the settlement rate in lieu of filing a motion to make effective its suspended

[1] The currently effective rate under Gordon Street, Inc.'s FPC Gas Rate Schedule No. 1 is 13.49751 cents per Mcf at 14.65 psia.

rate, cites the deletion of the flexible pricing provisions and indicated that such provisions were important components of the original contract. Tennessee Gas has concurred in the offer and has agreed to execute the contract amendment provided for therein. No comments or protests have been received with respect to the Offer of Settlement.

Since the proposed rate of 14.6 cents per Mcf at 14.65 psia is acceptable under the provisions of the Second Amendment to the Commission's Statement of General Policy No. 61–1 [18 CFR, Chapter I, Part 2, Section 2.56], issued December 20, 1960, for jurisdictional sales of natural gas for Texas Railroad Commission District No. 3, it is believed that the public interest will best be served by accepting Street's proposed settlement as hereinafter set forth.

However, we desire to make it clear that acceptance of this Offer of Settlement shall not be construed as approval of any future increased rates proposed by Street under the periodic escalation provisions or otherwise.

The Commission finds:

The proposed settlement of this rate proceeding on the basis described herein, as more fully set forth in the Offer of Settlement filed by Street with the Commission on May 1, 1962, is in the public interest and appropriate to carry out the provisions of the Natural Gas Act and should be approved by the Commission and made effective as hereinafter ordered.

The Commission orders:

(A) The Offer of Settlement filed by Street with the Commission on May 1, 1962, is hereby approved in accordance with the provision of this order.

(B) Street shall execute with Tennessee Gas, and shall file within 30 days from the date of issuance of this order, an amendment to its FPC Gas Rate Schedule No. 1, in the form required for a change in rate in accordance with Part 154 of the Commission's Regulations under the Natural Gas Act, which shall conform to Street's Offer of Settlement herein in all respects.

(C) Upon notification by the Secretary that Street has complied with the terms and conditions of this order, the rate and charge of 14.6 cents per Mcf specified in the Offer of Settlement shall be effective as of June 1, 1962 and the proceeding in Docket No. G–17722 shall be deemed terminated.

(D) The acceptance of this Offer of Settlement is without prejudice to any findings or determinations that may be made in any proceeding now pending or hereafter instituted against Street.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

METROPOLITAN EDISON COMPANY, PROJECT NO. 1888

ORDER DETERMINING NET CHANGE IN ACTUAL LEGITIMATE ORIGINAL PROJECT COST; ACCUMULATED PROVISION FOR DEPRECIATION; AND PRESCRIBING ACCOUNTING THEREFOR

(Issued May 23, 1962)

Metropolitan Edison Company, Licensee for Project No. 1888 (York Haven),[1] from time to time filed statements, pursuant to Section 4.1 of the Commission's Regulations under the Federal Power Act, claiming for the period from January

[1] The project is located on the Susquehanna River in Dauphin, Lancaster and York Counties, Pennsylvania. It may be described generally as the York Haven Project. The license issued pursuant to Section 4(e) of the Federal Power Act is by its terms effective for the period January 1, 1938 to June 30, 1970.

1, 1950 through December 31, 1960, project additions and retirements resulting in a net increase in project cost for that period of $297,106.75 over the previously determined amount of actual legitimate original cost of the project of $3,095,019.45 as of December 31, 1949 [2] and a resulting claimed actual legitimate original cost as of December 31, 1960 of $3,392,126.20. The claimed net increase of $297,106.75 results from claimed and recorded project additions and retirements totaling $477,130.36 and $181,786.14, respectively, and debit adjustments of $1,762.53, as is more specifically shown in the attached Schedule I.

Licensee also from time to time recorded upon its books of account additional accumulated provision for depreciation applicable to project properties from January 1, 1938, through December 31, 1960, resulting in a net increase in the recorded project depreciation reserve of $839,732.97, over the previously determined amount of reserve for accrued depreciation applicable to project properties, $847,966.29 as of January 1, 1938 [3] and a total recorded project depreciation reserve in the amount of $1,687,699.26 as of December 31, 1960.

The Commission's staff made a field examination of the books and records of Licensee and other data for the purpose of ascertaining the correctness of the above claimed and recorded project costs and reserves for depreciation.

Following that examination an agreement, subject to Commission approval, was reached between the staff and representatives of the Licensee with respect to certain proposed adjustments involving: (1) reclassification of project costs in the amount of $4,620.51 within the project plant accounts; (2) the elimination of $4,103.71 from the claimed and recorded project costs for the period from January 1, 1950 through December 31, 1960; (3) a decrease in the recorded project reserve for accrued depreciation for the period from January 1, 1938 through December 31, 1960, in the amount of $965.17; and (4) the accounting dispositions of all amounts involved in the foregoing proposed adjustments.

The accounting dispositions of the amounts involved in the proposed adjustments are shown by the following composite journal entry: [4]

Account No.	Title	Debit	Credit
108	Accumulated provision for depreciation of electric plant in service project No. 1888:		
	Hydraulic production	$847.09	
	Hydraulic production	535.26	
	Transmission	735.60	
		1,270.86	
163	Stores expense undistributed	58.30	
426	Other income deductions	3,080.24	
101	Electric plant in service project No. 1888		$4,103.71
	331, Structures and improvements	(2,832.85)	
	334, Accessory electric equipment	(49.62)	
	335, Misc. powerplant equipment	(5,106.15)	
	352, Structures and improvements	(735.60)	
	397, Communication equipment	4,620.51	
108	Accumulated provision for depreciation of electric plant in service project No. 1888:		
	Hydraulic production		305.69
	General		847.09

[2] See Commission order issued January 31, 1957, 17 FPC 131.

[3] Ibid.

[4] Account references are to account numbers and titles prescribed in the Commission's revised Uniform System of Accounts Prescribed for Public Utilities and Licensees effective January 1, 1961, except Schedule I which employs the account numbers and titles effective prior to January 1, 1961. This reflects the fact that the project costs herein are recorded in Licensee's plant accounts as of dates prior to January 1, 1961. Schedule I also shows the accounts effective as of January 1, 1961.

Based upon the proposed adjustments, the staff recommends and Licensee concurs, that the Commission determine: (1) the net increase or change in project costs for the period from January 1, 1950 through December 31, 1960, to be $293,003.04 composed of gross additions of $474,297.51, gross retirements of $183,057.00, and a net debit adjustment of $1,762.53; (2) the project actual legitimate original cost as of December 31, 1960, to be $3,388,022.49, classified by primary plant accounts of the Commission's Uniform System of Accounts as shown by Schedule I; (3) the net increase in the accumulated provision for depreciation applicable to inservice project properties for the period January 1, 1938 through December 31, 1960, to be the net credit amount of $838,767.80; and (4) the project depreciation reserve as of December 31, 1960, to be $1,686,734.09 classified by functional groups as shown in the attached Schedule II.

By letters dated July 10 and August 2, 1961, Licensee confirmed its agreement with respect to the proposed adjustments, accounting dispositions and resulting project costs and depreciation reserve.

By letter of this Commission dated September 25, 1961 the Pennsylvania Public Utility Commission was advised of the staff recommendations herein and resulting proposed project costs and depreciation reserve applicable to in-service project properties, all as described above. By letter of October 2, 1961 that Commission indicated its approval of the adjustments to project original cost and stated it had no comment with respect to the reserve for accrued depreciation since that Commission makes no determinations of depreciation reserve requirements for accounting purposes.

The Commission finds:

(1) Licensee, by its agreement to the proposed adjustments, including the accounting dispositions and the resulting project costs and depreciation reserve as stated in its letters of July 10 and August 2, 1961, and the Pennsylvania Public Utilities Commission by its letter of October 2, 1961, have obviated the necessity for notice and opportunity for protest provided by Sections 4.4 and 4.5, of the Commission's Regulations under the Federal Power Act.

(2) The foregoing adjustments, including the accounting dispositions, are reasonable and appropriate for the purposes of the Federal Power Act, and therefore, should be approved and directed as hereinafter provided.

(3) The net increase or change in the actual legitimate original cost of Project No. 1888 during the period from January 1, 1950 through December 31, 1960, is $293,003.04 consisting of gross additions of $474,297.51, gross retirements of $183,057.00, and debit adjustments of $1,762.53; and the resulting actual legitimate original cost of Project No. 1888 as of December 31, 1960 is $3,388,022.49, classified by primary plant accounts of the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees as more specifically shown in the attached Schedule I.

(4) The net increase or change in the accumulated provision for depreciation applicable to in-service project properties during the period from January 1, 1938 through December 31, 1960 is $838,767.80; and the resulting project depreciation reserve applicable to in-service project properties as of December 31, 1960 is $1,686,734.09 classified by functional groups as more specifically shown on the attached Schedule II.

SCHEDULE I

Actual legitimate original cost

Account No.	Account Description	* Approved project cost as of Dec. 31, 1949	Changes from 1-1-1950 to 12-31-1960				Approved project cost as of Dec. 31, 1960	Account No. effective Jan. 1, 1961
			As claimed	Proposed staff		As adjusted		
				Reclassification	Adjustments			
	Hydraulic production plant:							
320	Land and land rights	$104,709.94	$1,150.28			$1,150.28	$105,860.22	330
321	Structures and improvements	147,756.26	38,121.63		($2,832.85)	35,288.78	183,045.04	331
322	Reservoirs, dams and waterways	1,545,934.67	109,840.28			109,840.28	1,655,774.95	332
323	Water wheels, turbines, and generators	768,303.66	14,643.29			14,643.29	782,946.95	333
324	Accessory electric equipment	209,201.78	8,147.88		(49.62)	8,098.26	217,300.04	334
325	Miscellaneous powerplant equipment	80,299.92	64,572.75	(4,620.51)	(485.64)	59,466.60	139,766.52	335
326	Roads, railroads, and bridges	2,176.16					2,176.16	336
	Total hydraulic production plant	2,858,382.39	236,476.11	(4,620.51)	(3,368.11)	228,487.49	3,086,869.88	
	Transmission plant:							
342	Structures and improvements	35,164.62	192.67		(735.60)	(542.93)	34,621.69	352
343	Station equipment	201,047.98	60,862.43			60,862.43	261,910.41	353
	Total transmission plant	236,212.60	61,055.10		(735.60)	60,319.50	296,532.10	
378	General Plant: Communication equipment	424.46	(424.46)	4,620.51		4,196.05	4,620.51	397
	Total actual legitimate original cost	3,095,019.45	297,106.75		(4,103.71)	293,003.04	3,388,022.49	

*Commission Order issued January 31, 1957, 17 FPC 131.

( ) Denotes credit.

The Commission orders:

(A) The provisions of Sections 4.4 and 4.5 of the Commission's Regulations under the Federal Power Act are hereby waived for the purposes of this order.

(B) The foregoing adjustments including the accounting dispositions, as proposed by the Commission's staff and agreed to by Licensee, are hereby approved and directed to be made by Licensee.

(C) Licensee, to the extent that it has not already done so, shall: (a) establish and maintain control and detailed accounts for Project No. 1888, showing the debit amount of $293,003.04 as net increase or change in the project cost for the period from January 1, 1950 through December 31, 1960; and the total debit balance of $3,388,022.49 as of December 31, 1960; all as more specifically shown by primary plant accounts as set forth in the attached Schedule I; and (b) establish and maintain an account for accumulated provision for depreciation applicable to in-service project properties of Project No. 1888, showing the credit balance of $847,966.29 as of January 1, 1938; the credit amount of $838,767.80 as the net increase or change in the project depreciation reserve applicable to in-service project properties for the period from January 1, 1938 through December 31, 1960; and the credit balance of $1,686,734.09 as of December 31, 1960; all classified by functional groups as shown in the attached Schedule II.

(D) Lincensee shall within 60 days from the issuance of this order file three certified copies of its adjusting journal entries showing compliance with this order.

SCHEDULE II

Accumulated provision for depreciation of electric plant in service, summary by functional groups, as of December 31, 1960

	Approved project plant	Approved project accumulated provision for depreciation	Percent of plant
Depreciable:			
Hydraulic Production	$2,981,009.66	$1,600,279.85	53.68
Transmission	296,532.10	85,607.15	28.87
General	4,620.51	847.09	18.33
Total Depreciable	3,282,162.27	1,686,734.09	51.39
Nondepreciable:			
Hydraulic production: Land and land rights	105,860.22		
Total project electric plant in service	3,388,022.49		

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

PACIFIC GAS & ELECTRIC COMPANY, PROJECT NO. 99

ORDER DETERMINING NET CHANGE IN ACTUAL LEGITIMATE ORIGINAL PROJECT COST AND PRESCRIBING ACCOUNTING THEREFOR

(Issued May 23, 1962)

Pacific Gas & Electric Company, Licensee for Project No. 99 (Canyon Creek),[1] from time to time filed statements, pursuant to section 4.1 of the Commission's

[1] The project is located on Canyon Creek in Humboldt and Trinity Counties, California, and affects lands of the United States within Trinity and Six Rivers National Forest and other lands of the United States. The license (issued pursuant to Section 4(d) of the Federal Water Power Act), authorizing the maintenance and operation of the project, is by its terms effective for a period commencing February 12, 1923 and terminating February 11, 1973.

Regulations under the Federal Power Act claiming for the period from February 13, 1923 through December 31, 1957, project additions and retirements resulting in a net increase in project cost for that period of $1,699,559.73 over the previously determined amount of actual legitimate original cost of the project of $705,839.00 as of February 12, 1923[2] and a resulting total claimed actual legitimate original cost of the project as of December 31, 1957 of $2,405,398.73. The claimed net increase of $1,699,599.73, results from claimed and recorded project gross additions, gross retirements, and credit adjustments totaling $2,444,899.21, $665,242.17 and $80,097.31,[3] respectively, and is more specifically shown in the attached Schedule I.

The Commission's staff made a field examination of the books and records of Licensee for the purpose of ascertaining the correctness of the claimed and recorded project cost changes and resulting project cost as of December 31, 1957.

Following that examination, an agreement, subject to Commission approval, was reached between the staff and Licensee's representatives with respect to certain proposed revisions in project plant accounts involving: (1) the elimination of $259,963.14 from the claimed project costs for the period from February 13, 1923 through December 31, 1957; (2) the addition to the project plant accounts of $59,755.85 to reconcile recorded costs with claimed costs as of December 31, 1957; (3) the reclassification within project plant accounts of a total of $11,004.61 which does not result in a change in over-all project costs; and (4) the accounting disposition thereof in the manner shown in the composite entry and in the attached Schedule II.

Based upon the foregoing, the resulting revised total net increase or change in project cost for the period February 13, 1923 through December 31, 1957, would be $1,439,596.59, consisting of gross additions of $2,256,897.04, gross retirements of $720,790.14 and a net credit adjustment of $96,510.31;[4] resulting in a total actual legitimate original cost of the project as of December 31, 1957 of $2,145,435.59.

The proposed revisions required to be made to the recorded costs as enumerated above are composed of the following items:

Nonproject items	$(96,043.81)
Overstated, understated and unrecorded retirements	(68,480.85)
Operating expenses and removal costs improperly capitalized	(72,782.05)
Excess interest during construction charges	(20,978.28)
Other improper charges	(1,678.15)
Total revisions to claimed cost	(259,963.14)
Reconcile recorded costs to claimed costs	59,755.85
Net revision required to bring recorded cost into agreement with recommended cost, as of December 31, 1957	(200,207.29)

[2] See Commission order *13th Annual Report of the F.P.C.* (1933) page 186. Article 13 of the license provides for Commission determination of the fair value of the project as of February 12, 1923.

[3] This amount consists of claimed credit adjustments of $79,220.76 and contributions in aid of construction-Federal in the credit amount of $876.55.

[4] This amount consists of: $95,633.76 transferred to nonproject plant which represents the cost of the Eureka Substation and 5.1 miles of transmission line from the Eureka to the Humboldt Substation; and contributions in aid of construction-Federal, in the credit amount of $876.55.

The proposed accounting disposition of all amounts involved in the proposed adjustments to bring Licensee's recorded project costs into agreement with the recommended project cost, as tentatively agreed to between Licensee and the staff are shown by the following composite journal entry:

	Accounts	Debit	Credit
[4] 101	Electric plant in service—nonproject	$23,660.27	
108	Accumulated provision for depreciation of electric plant in service—:		
	Project No. 99	53,154.92	
	Nonproject	13,133.99	
262	Injuries and damages reserve	17,861.21	
216	Unappropriated earned surplus	20,858.37	
400	Operating revenues	486.16	
401	Operation expense	49,681.44	
408	Taxes other than income taxes	392.65	
432	Interest charged to construction—Cr	20,978.28	
101	Electric plant in service—project No. 99		$200,207.29

After giving effect to the above adjustments, Commission staff recommends and Licensee, by letter dated April 7, 1961, confirms its agreement to the proposed adjustments, net change and resulting actual legitimate original project costs as of December 31, 1957, and that the Commission determine:

(1) The net increase or change in the actual legitimate original cost of Project No. 99 during the period from February 13, 1923 through December 31, 1957 to be $1,439,596.59, consisting of gross additions of $2,256,897.04, gross retirements of $720,790.14 and a net credit adjustment of $96,510.31.

(2) The resulting actual legitimate original cost of Project No. 99 as of December 31, 1957 to be $2,145,435.59, classified by primary plant accounts of the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees as shown in attached Schedule I.

The matter of accumulated provision for depreciation applicable to in-service properties, Project No. 99, is currently under study by the Commission's staff. Previously, the Commission in determining Licensee's net investment in Project No. 99 as of February 12, 1923 ($661,619), determined: "That the sum of $44,220 was the equitable proportion assignable to said project out of the credit balance in the depreciation reserve of Western States Gas and Electric Co. [original licensee] as of December 31, 1922, accumulated out of the earnings of said company prior to said date * * *." *Thirteenth Annual Report of the Federal Power Commission* p. 187. The recommendations of Commission's staff and Licensee here before the Commission contemplate that the matter of accumulated provision for depreciation applicable to in-service project properties accruing subsequent to February 12, 1923 will be presented for Commission consideration and determination at a later time.

The California Public Utilities Commission by letter of November 28, 1961 has advised that it has no objection to the proposed adjustments, accounting disposition and resulting project costs, all as described above.

[4] Account references are to account numbers and titles prescribed in the Commission's revised Uniform System of Accounts for Public Utilities and Licensees effective January 1, 1961, except Schedules I and II which employ the account numbers and titles effective prior to January 1, 1961. This reflects the fact that the project costs herein are recorded in Licensee's plant accounts as of dates prior to January 1, 1961.

The Commission finds:

(1) Licensee, by its agreement to the proposed adjustments, including the accounting dispositions and the resulting project costs, as stated in its letter of April 7, 1961, and the California Public Utilities Commission by its letter of November 28, 1961 have obviated the necessity for notice and opportunity to protest provided by Sections 4.4 and 4.5 of the Commission's Regulations under the Federal Power Act.

(2) The foregoing adjustments, including the accounting dispositions, are reasonable and appropriate for the purposes of the Federal Power Act, and therefore, should be approved and directed as hereinafter provided.

(3) The net increase or change in the actual legitimate original cost of Project No. 99 during the period from February 13, 1923, through December 31, 1957, is $1,439,596.59, consisting of gross additions of $2,256,897.04, gross retirements of $720,790.14, and a net credit adjustment of $96,510.31; and the resulting actual legitimate original cost of Project No. 99, as of December 31, 1957, is $2,145,435.59, classified by primary accounts as shown in attached Schedule I.

(4) It is necessary and appropriate for the purposes of the Federal Power Act that the matter of determining the accumulated provision for depreciation applicable to in-service project properties accruing subsequent to February 12, 1923 be reserved for future Commission consideration and decision as hereinafter ordered.

The Commission orders:

(A) The provisions of Sections 4.4 and 4.5 of the Commission's Regulations under the Federal Power Act are hereby waived for the purposes of this order.

(B) The foregoing adjustments, including the accounting dispositions, as proposed by the staff and agreed to by the Licensee, are hereby approved and directed to be made by the Licensee.

(C) Licensee, to the extent that it has not already done so, shall establish and maintain control and detailed plant accounts for Project No. 99, showing the debit amount of $1,439,596.59 as the net increase or change in the project cost for the period from February 13, 1923 through December 31, 1957; and the total debit balance of $2,145,435.59 as of December 31, 1957; all as more specifically shown by primary plant accounts as set forth in the attached Schedule I.

(D) Licensee shall within 60 days from the issuance of this order file three certified copies of its adjusting journal entries showing compliance with this order.

(E) The matter of Commission determination of the amount of accumulated provision for depreciation applicable to in-service project properties accruing subsequent to February 12, 1923 is hereby expressly reserved for future Commission consideration and decision.

SCHEDULE 1

Summary by detailed plant accounts of agreed project cost as of February 12, 1923, claimed charges for the period February 13, 1923–December 31, 1957, adjustments thereto and balances allowed as of December 31, 1957

[( ) Denotes credits]

Account [1]		Agreed project cost as of February 12, 1923			Changes from February 13, 1923 to December 31, 1957, inclusive			Allowed cost as of Dec. 31, 1957
No.	Title	Per agreement dated April 17, 1933 [2]	Reclassification per Commission order issued Feb. 27, 1950 [2]	Reclassified total	As claimed	Staff proposed adjustments	Recommended for allowance	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
100.1	ELECTRIC PLANT IN SERVICE							
	Production Plant							
	Uniform System of Accounts Effective Nov. 20, 1922:							
312	Hydraulic power plant land	$155.00	$(155.00)					
313	Hydraulic power plant structures	20,212.50	(20,212.50)					
314	Reservoirs, dams, and intakes	5,696.00	(5,696.00)					
316	Waterways	229,627.00	(229,627.00)					
317	Forebays, penstocks, and tailraces	31,754.00	(31,754.00)					
318	Production roads and trails	3,046.50	(3,046.50)					
319	Water turbines and water wheels	29,119.00	(29,119.00)					
320	Electric equipment—Hydro	36,145.00	(36,145.00)					
323	Miscellaneous powerplant equipment—hydro	2,399.00	(2,399.00)					
	Uniform system of accounts effective Jan. 1, 1937:							
320	Land and land rights		155.00	$155.00	$1,291.60		$1,291.60	$1,446.60
321	Structures and improvements		22,547.50	22,547.50	50,276.50	$(5,984.60)	44,291.90	66,839.40
322	Reservoirs, dams, and waterways		267,902.00	267,902.00	345,979.25	(36,747.52)	309,231.73	577,133.73
323	Water wheels, turbines, and generators		55,863.00	55,863.00	15,674.03	144.86	15,818.89	71,681.89
324	Accessory electric equipment		9,401.00	9,401.00	39,504.12	946.44	40,450.56	49,851.56
325	Miscellaneous powerplant equipment		2,399.00	2,399.00	4,605.30	178.63	4,783.93	7,182.93
326	Roads, railroads, and bridges		3,046.50	3,046.50	2,868.29	(65.43)	2,803.86	5,850.36
	Total production plant	358,154.00	3,160.00	361,314.00	460,200.09	(41,527.62)	418,672.47	779,966.47

	Transmission Plant							
	Uniform System of Accounts Effective Nov. 20, 1922:							
331	Transmission land	54,994.00	(54,994.00)					
332	Transmission structures	6,359.00	(6,359.00)					
333	Transmission substation equipment	42,525.00	(42,525.00)					
336	Transmission poles and fixtures	90,911.00	(90,911.00)					
337	Transmission pole line conductors	120,236.00	(120,236.00)					
340	Transmission roads and trails	12,575.00	(12,575.00)					
341	Miscellaneous transmission capital	1,077.00	(1,077.00)					
	Uniform System of Accounts Effective Jan. 1, 1937:							
340	Land and land rights		19,737.00	19,737.00	11,180.13	(14,501.44)	(3,321.31)	16,415.69
341	Clearing land and rights-of-way		35,257.00	35,257.00	164,108.63	(44,558.46)	119,550.17	154,807.17
342	Structures and improvements		3,199.00	3,199.00	(64.68)	3,114.59	3,049.91	6,248.91
343	Station equipment		42,821.00	42,821.00	61,541.98	(36,924.23)	24,617.75	67,438.75
344	Towers and fixtures				41,781.44	(1,580.16)	40,201.28	40,201.28
345	Poles and fixtures		90,911.00	90,911.00	479,262.89	(6,955.00)	472,307.89	563,218.89
346	Overhead conductors and devices		120,236.00	120,236.00	363,582.11	(58,144.67)	305,437.44	425,673.44
349	Roads and trails		12,575.00	12,575.00	(1,441.92)		(1,441.92)	11,133.08
	Total transmission plant	328,677.00	(3,941.00)	324,736.00	1,119,950.58	(159,549.37)	960,401.21	1,285,137.21
	General Plant							
382	Uniform System of Accounts Effective Nov. 20, 1922: Communication System Equipment	19,008.00	19,008.00					
	Uniform System of Accounts Effective Jan. 1, 1937:							
370	Land and land rights				283.50	(1.83)	281.67	281.67
373	Transportation equipment		390.00	390.00	(42.45)	(347.55)	(390.00	
377	Tools and work equipment				290.75	(11.61)	279.14	279.14
378	Communication equipment		19,008.00	19,008.00	119,522.29	(58,519.23)	61,003.06	80,011.06
379	Miscellaneous equipment		391.00	391.00	231.52	(5.93)	225.59)	616.59
	Total general plant	19,008.00	781.00	19,789.00	120,285.61	(58,886.15)	61,399.46	81,188.46
	Total Electric Plant in Service	705,839.00		705,839.00	1,700,436.28	(259,963.14)	1,440,473.14	2,146,312.14
265.2	Contributions in Aid of Construction-Federal				(876.55)		(876.55)	(876.55)
	Total actual legitimate original cost	705,839.00		705,839.00	1,699,559.73	(259,963.14)	1,439,596.59	2,145,435.59

[1] Account numbers and titles effective prior to January 1, 1961.
[2] Agreement on net investment, instrument No. 4, Project No. 99, authorized April 12, 1933 (13th Annual Report of F.P.C.—1933, Pages 186 and 195)

[3] 9 FPC 545.

SCHEDULE II

Adjustments of recorded and claimed changes in the project plant accounts and accounting disposition thereof for the period from February 13, 1923–December 31, 1957

[( ) Denotes credits]

Account [1]		Total	To adjust recorded cost to claimed cost				Proposed adjustments to claimed changes						
No.	Title		Subtotal	Addition to nonproject pit No. 1 powerhouse recorded in project accounts	Project equipment in Eureka Station "A" recorded in nonproject accounts	Nonproject telephone line claimed as project	Subtotal	No. 1 Nonproject items	No. 2 Overstated, understated and unrecorded retirements	No. 3 Operating expenses and removal costs improperly capitalized	No. 4 Excess interest during construction charges	No. 5 Other improper charges	No. 6 Reclassifications within detailed plant accounts
100.1	ELECTRIC PLANT IN SERVICE												
	Hydraulic production plant:												
321	Structures and improvements	$(8,207.04)	$(2,222.44)	$(2,222.44)			$(5,984.60)	$(23.76)	$298.35	$(2,393.23)	$(713.68)	$(183.93)	$(2,968.35)
322	Reservoirs, dams, and waterways	(36,747.52)					(36,747.52)	(4,134.75)	(20,210.56)	(9,449.69)	(2,552.87)	(208.00)	(191.65)
323	Water wheels, turbines, and generators	144.86					144.86			1,324.80	(991.05)	(189.19)	.30
324	Accessory electric equipment	946.44					946.44		2,278.21	(152.06)	(961.35)	(218.06)	(.30)
325	Miscellaneous power plant equipment	178.63					178.63	(12.01)	217.20	24.42	(36.12)	(14.86)	
326	Roads, railroads, and bridges	(65.43)					(65.43)			(37.84)	(22.69)	(4.90)	
	Total hydraulic production plant	(43,750.06)	(2,222.44)	(2,222.44)			(41,527.62)	(4,170.52)	(17,416.80)	(10,683.60)	(5,277.76)	(818.94)	(3,160.00)
	Transmission plant:												
340	Land and land rights	(14,501.44)					(14,501.44)	357.73	(6,578.92)	(384.25)	(50.18)	(1.51)	(7,844.31)
341	Clearing land and rights-of-way	(44,558.46)					(44,558.46)	(3,635.41)	(13,986.41)	(24,539.02)	(2,514.67)		117.05
342	Structures and improvements	3,114.59					3,114.59	158.05	(190.20)	(1.70)	(11.56)		3,160.00
343	Station equipment	(753.88)	36,170.35		36,170.35		(36,924.23)	(39,187.34)	2,954.44	126.19	(630.54)	(186.98)	
344	Towers and fixtures	(1,580.16)					(1,580.16)	(130.91)	(203.14)	(306.77)	(939.34)		
345	Poles and fixtures	(6,955.00)					(6,955.00)	(13,240.23)	14,251.33	(9,020.40)	(6,504.95)	(168.01)	7,727.26

345	Poles and fixtures	(6,955.00)					(6,955.00)	(13,240.23)	14,251.33	(9,020.40)	(6,504.95)	(168.01)	7,727.26
346	Overhead conductors and devices	(58,144.67)					(58,144.67)	(8,574.97)	(19,413.96)	(26,374.11)	(3,363.58)	(418.05)	
	Total transmission plant	(123,379.02)	36,170.35		36,170.35		(159,549.37)	(64,253.08)	(23,166.86)	(60,500.06)	(14,014.82)	(774.55)	3,160.00
352	Distribution plant: Station equipment	(1,756.73)	(1,756.73)		(1,756.73)								
	General plant:												
370	Land and land rights	(1.83)					(1.83)			(1.83)			
373	Transportation equipment	(347.55)					(347.55)		(347.55)				
377	Tools and work equipment	(11.61)					(11.61)	(8.43)			(3.18)		
378	Communication equipment	(30,954.56)	27,564.67			27,564.67	(58,519.23)	(27,608.02)	(27,549.64)	(1,596.56)	(1,680.35)	(84.66)	
379	Miscellaneous equipment	(5.93)					(5.93)	(3.76)			(2.17)		
	Total general plant	(31,321.48)	27,564.67			27,564.67	(58,886.15)	(27,620.21)	(27,897.19)	(1,598.39)	(1,685.70)	(84.66)	
	Total electric plant in service	(200,207.29)	59,755.85	(2,222.44)	34,413.62	27,564.67	(259,963.14)	(96,043.81)	(68,480.85)	(72,782.05)	(20,978.28)	(1,678.15)	
	Recommended accounting disposition:												
100.1	Electric plant in service—nonproject	23,660.27	(59,755.85)	2,222.44	(34,413.62)	(27,564.67)	83,416.12	82,909.82	506.30				
250.1	Reserve for depreciation of electric plant in service:												
	Project	53,154.92					53,154.92		47,316.59	5,838.33			
	Nonproject	13,133.99					13,133.99	13,133.99					
256	Injuries and damages reserve	17,861.21					17,861.21			17,861.21			
271	Earned surplus	20,858.37					20,858.37		20,059.03			799.34	
501	Operating revenues	486.16					486.16					486.15	
502	Operating expenses	49,681.44					49,681.44		598.93	49,082.51			
507	Taxes	392.65					392.65					392.65	
536	Interest charged to construction—credit	20,978.28					20,978.28				20,978.28		
	Total recommended accounting disposition	200,207.29	(59,755.85)	2,222.44	(34,413.62)	(27,564.67)	259,963.14	96,043.81	68,480.85	72,782.05	20,978.28	1,678.15	

[1] Account numbers and titles effective prior to January 1, 1961.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

TAPOCO, INC., PROJECT NO. 2169

ORDER APPROVING REVISED PROJECT EXHIBIT

(Issued May 23, 1962)

Application was filed on March 5, 1962 by Tapoco, Inc., licensee for major Project No. 2169, for Commission approval of revised Exhibit K showing the proposed installation as part of the project works of remote control equipment which would permit operation of the Santeetlah power plant from the Cheoah power plant. Both of these plants are parts of Project No. 2169.

Installation of the remote control equipment will include the dismantling and elimination from the license of the telephone line now running between the Santeetlah and Cheoah powerhouses, and of the telephone line from the Santeetlah powerhouse to the Santeetlah dam. When the automatic control system is installed at Santeetlah, it will be operated by signals sent on carrier circuits over the Cheoah-Santeetlah power transmission line. The telephone line between Santeetlah powerhouse and Santeetlah dam was formerly used to telemeter water level and rainfall data. With its dismantlement, such data will be furnished to the system operators by cruising personnel and transmitted by radio-telephone over the power transmission line.

The Commission finds:

Revised Exhibit K-2, Sheets 11, 12, 13, 15 and 17 (FPC Nos. 2169-71 through -75) conforms to the Commission's rules and regulations and should be approved as part of the license for the project, and Exhibit K-2 (FPC Nos. 2169-52, -53, -54, -56, and -58) now part of the license and which has been superseded, should be eliminated from the license for the project—all as hereinafter provided.

The Commission orders:

The revised Exhibit K described in the above finding is approved as part of the license for Project No. 2169, and the Exhibit K described in the same finding as being superseded is eliminated from the license for the project.

Before Commissioners: Joseph C. Swidler, Chairman: Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

AMERICAN GAS COMPANY OF WISCONSIN, INC., DOCKET NO. CP62-104; MIDWESTERN GAS TRANSMISSION COMPANY, DOCKET NO. G-18313

FINDINGS AND ORDER DIRECTING PHYSICAL CONNECTION OF FACILITIES AND SALE OF NATURAL GAS AND AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 24, 1962)

On October 23, 1961, American Gas Company of Wisconsin (American), a Wisconsin corporation having its principal office in Madison, Wisconsin, filed an application and on November 1, and December 12, 1961, supplements thereto, pursuant to Section 7(a) of the Natural Gas Act, for an order directing Midwestern Gas Transmission Company (Midwestern) to establish physical con-

nection of its transportation facilities with the facilities proposed to be constructed by American, and to sell and deliver to American up to 3500 Mcf of natural gas per day for resale and distribution to the public in the communities of Cadott, Boyd, Stanley, Jim Falls, and Cornell in Chippewa County; Thorp, Withee, Owen, Curtiss, and Dorchester in Clark County; Abbotsford, Colby, and Unity in Clark and Marathon Counties, and Stetsonville and Medford in Taylor County, all in the State of Wisconsin.

American proposes to construct and operate distribution systems in each community and approximately 5.9 miles of 6⅝-inch lateral transmission line extending northeast from an interconnection with Midwestern's main transmission line in Wisconsin, to the community of Cadott and approximately 61.6 miles of 4½-inch, 13.6 miles of 3½-inch, and 6.3 miles of 2⅜-inch transmission line extending from Cadott to the other 14 communities. American also proposes to construct and operate peak shaving plants at Medford and Cornell, Wisconsin. It is proposed that the deliveries of the gas requirements for all fifteen communities will be made at the point of interconnection with Midwestern's system.

The estimated natural gas requirements of said communities are as follows:

Year	Mcf at 14.73 psia and 1,000 Btu	
	Peak Day	*Annual*
1	2,474	915,152
2	3,711	1,210,605
3	4,574	1,520,782

American and Midwestern show that Midwestern has a sufficient supply of natural gas to meet the request of American for 3500 Mcf per day, and American shows that it will install peak shaving facilities at Medford for the second year of operation and at Cornell for the third year of operation.

Midwestern filed on November 24, 1961, an answer and on January 8, 1962, a supplemental answer to American's application, stating that its total unallocated gas supply was 3,537 Mcf and that it did not oppose said application. On January 22, 1962, Midwestern filed a supplemental answer to the application and also a motion to amend Opinion No. 331 issued on October 31, 1959, wherein Midwestern was issued a certificate of public convenience and necessity. Midwestern requests that in the event the Commission orders Midwestern to serve American the natural gas requirements requested in the application in Docket No. CP62-104, the Commission further amend Opinion No. 331, issued October 31, 1959, by reallocating the volumes of natural gas that Midwestern is obligated to deliver to its customers as proposed in "Analysis of Third Year Contract Demand Allocation" schedule attached to its said motion to amend as Exhibit A. Midwestern in notes attached to its motion explained the reasons for the proposed reallocation of volumes as follows:

(1) The Commission's Order dated August 19, 1960 allowed Northern States Power Company to increase its contract demand from 29,200 Mcf to 29,530 Mcf and United Petroleum Gas Company to reduce its contract demand from 1,847 Mcf to 1,517 Mcf. This transfer of 330 Mcf from United Petroleum to Northern States is the result of Northern States being granted authorization to render service to the Village of Dilworth instead of United Petroleum.

(2) The Commission's Order dated September 2, 1960 allowed United Petroleum Gas Company to increase its contract demand from 1,517 Mcf (as author-

ized in the Commission's Order dated August 19, 1960) to 2,117 Mcf. This increase is the result of United Petroleum rendering service to Ada, Minnesota. However, Opinion 331 allocated 992 Mcf to the City of Ada, Minnesota and United Petroleum requested an increase in contract of 600 Mcf for the city. The difference of 392 Mcf increased Midwestern's "Reserved for Future Sales" volume from 2,790 Mcf to 3,182 Mcf.

(3) The Commission's Order dated March 17, 1961 allocated to the City of Warren, Minnesota 818 Mcf and reduced the contract demand to United Petroleum Gas Company from 2,117 Mcf to 2,043 Mcf. Midwestern was able to render this service to Warren by reducing its "Reserved for Future Sales" volume by 742 Mcf and utilizing the 74 Mcf released by United Petroleum.

(4) The Commission's Order dated August 24, 1961 at Docket No. CP61–306 directed Midwestern to serve North Central Public Service Company 350 Mcf per day out of the unallocated gas supply of 2,438 Mcf. On September 15, 1961 Midwestern and the Village of Perham, Minnesota entered into a new contract for 600 Mcf which was 360 Mcf less than the original allocation to Perham. As a result of the Commission's Order and Perham's adjusted allocation, Midwestern had 2,450 Mcf of unallocated gas supply.

(5) As a result of the Commission's Order dated August 7, 1961 authorizing Midwestern to substitute three 1,700 horsepower compressor units, with an improved fuel factor design, for four 1,320 horsepower units, Midwestern now estimates its fuel requirements to be 544 Mcf less than the originally authorized 2,600 Mcf.

United Petroleum Gas Company has requested a reduction of 543 Mcf in its contract demand as a result of their planned loads not developing. The reduction in fuel requirements and the additional gas indicated as available from United Petroleum increased Midwestern's unallocated gas supply by 1,087 Mcf to a total of 3,537 Mcf.

The estimated total cost of American's proposed facilities is $3,142,410, which will increase to $3,499,160 in the third year of operation, and which will be financed by the issuance and sale of $1,150,000 of its common stock to its parent, American Gas Company, an Iowa corporation and by the sale of approximately $2,200,000 of its 6½ percent first mortgage bonds and from retained earnings.

Midwestern will install the necessary tap and measuring facilities at the proposed point of connection at an estimated cost of $20,000.

On April 6, 1962, the Public Service Commission of Wisconsin filed a notice of intervention herein. By letter dated March 6, 1962, said Public Service Commission of Wisconsin advised the Federal Power Commission that it had on December 7, 1961, issued an order authorizing American to operate as a gas public utility and to furnish natural gas to the public in the fifteen above-named communities. On May 4, 1962, the Wisconsin Commission transmitted to this Commission a copy of its said order of December 7, 1961, in its Docket No. CA–4034. A copy of said order has also been submitted by American on December 12, 1961, as a part of its application.

On March 26, 1962, Fuels Research Council, Inc., National Coal Association, United Mine Workers of America, Mid-West Coal Producers Institute, Inc., and Upper Lake Docks Coal Bureau, Inc., filed a joint petition for leave to intervene herein, but on May 15, 1962, said petitioners filed a notice of withdrawal of their joint petition to intervene.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 17, 1962, respecting the matters involved in and the issues presented by the application and motion to amend. No petition to intervene or protest to the

granting of the application and motion to amend, except the above-described joint petition, which joint petitioners now request to withdraw, and the notice of intervention, filed by the Public Service Commission, which does not oppose said application and motion. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Midwestern Gas Transmission Company, a Delaware corporation, having its principal office in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission.

(2) American Gas Company of Wisconsin, Inc., a Wisconsin corporation, having its principal office in Madison, Wisconsin, is duly authorized to engage in the distribution of natural gas to the public in the State of Wisconsin and holds a certificate issued by the Public Service Commission of Wisconsin, authorizing it to install facilities and deliver and sell natural gas to the public in the above-named fifteen communities, and American also holds franchises from each of said communities authorizing the service proposed.

(3) It is necessary and desirable in the public interest to direct Midwestern Gas Transmission Company to establish physical connection of its transmission system with the facilities proposed to be contructed and operated by American Gas Company of Wisconsin, Inc., and to sell and deliver up to 3500 Mcf per day of natural gas to American Gas Company of Wisconsin, Inc., for resale and distribution in the communities of Cadott, Boyd, Stanley, Jim Falls, and Cornell in Chippewa County; Thorp, Withee, Owen, Curtiss, and Dorchester in Clark County; Abbotsford, Colby, and Unity in Clark and Marathon Counties and Stetsonville and Medford in Taylor County, all in the State of Wisconsin.

(4) The requirement that Midwestern serve American as proposed will not place an undue burden upon Midwestern nor impair its ability to render adequate service to its existing customers, nor will Midwestern be compelled to enlarge its transportation facilities.

(5) Good cause has been shown for granting Midwestern's motion to amend Opinion No. 331 issued on October 31, 1959, in Docket No. G–18313, as hereinafter ordered.

(6) A request during the public hearing having been made by staff counsel for omission of the intermediate decision procedure, and all requirements of Section 1.30(c)(1) [18 CFR 1.30(c)(1)] of the Commission's Rules of Practice and Procedure having been satisfied, sufficient cause exists for the Commission to render its final decision in the instant proceeding.

The Commission orders:

(A) Midwestern Gas Transmission Company be and it is hereby directed to establish physical connection of its transportation facilities with the facilities proposed to be constructed and operated by American Gas Company of Wisconsin, Inc., as hereinbefore described, and to sell and deliver up to 3,500 Mcf of natural gas per day to said American Gas Company of Wisconsin, Inc., under Midwestern's appropriate FPC rate schedule, for resale and distribution in the communities of Cadott, Boyd, Stanley, Jim Falls, and Cornell in Chippewa County; Thorp, Withee, Owen, Curtiss, and Dorchester in Clark County; Abbotsford, Colby, and Unity in Clark and Marathon Counties and Stetsonville and Medford in Taylor County, all in the State of Wisconsin.

(B) Midwestern shall report to the Commission in writing and under oath the date of commencement of service to American within 30 days after the commencement of such service.

(C) American shall be prepared to receive natural gas from Midwestern within one year from the date of issuance of this order.

(D) The motion of Midwestern Gas Transmission Company to amend the Commission's Opinion No. 331 issued October 31, 1959, be and the same is hereby granted and the present allocation of natural gas set forth in Opinion No. 331 is hereby revised in accordance with Exhibit A attached to Midwestern's motion. Accordingly, Midwestern is hereby authorized to sell natural gas to the following customers in the amounts stated:

	Contract demand (Mcf)
Argyle, Minnesota (Village of)	366
Frazee, Minnesota (Village of)	565
Hallock, Minnesota (Village of)	769
Hawley, Minnesota (Village of)	612
Lake Park, Minnesota (Village of)	355
Michigan-Wisconsin Pipe Line Company	158,000
Montana-Dakota Utilities Company	4,000
New York Mills, Minnesota (Village of)	537
North Central Public Service Company	350
Northern States Power Company—	
Chippewa Falls	2,390
Dilworth	330
East Grand Forks	1,160
Eau Claire	7,200
Fargo	8,900
Grand Forks	5,310
Menomonie	1,680
Moorhead	2,560
Total Northern States Power Company	29,530
Perham, Minnesota (Village of)	600
Stephen, Minnesota (Village of)	405
United Petroleum Gas Company—	
Ada	600
Detroit Lakes	900
Total United Petroleum Gas Company	1,500
Warren, Minnesota (City of)	818
American Gas Company of Wisconsin, Inc	3,500
Total contract demand	201,907
Fuel	2,056
Unallocated	37
Total supply	204,000

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NORTHERN STATES POWER COMPANY, DOCKET NO. E-7035

ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTGAGE BONDS

(Issued May 24, 1962)

Northern States Power Company (Applicant), incorporated under the laws of the State of Minnesota and doing business in the States of Minnesota, North Dakota and South Dakota, with its principal place of business in Minneapolis, Minnesota, filed an application, on April 26, 1962, for authority, pursuant to Section 204 of the Federal Power Act, to issue and sell at competitive bidding $15,000,000, principal amount of First Mortgage Bonds, due 1992.

Applicant proposes to issue the Bonds under a Trust Indenture, dated February 1, 1937 from Applicant to Harris Trust and Savings Bank of Chicago, Trustee, as heretofore supplemented and as to be further supplemented by a proposed new Supplemental Indenture to be dated as of June 1, 1962. The new Bonds will be dated as of June 1, 1962 and will mature on June 1, 1992. The interest rate of the Bonds will be determined by competitive bidding.

On or about June 5, 1962, Applicant proposes to invite sealed, written bids for the purchase of the Bonds by newspaper publication and by distribution of a Form of Proposal, together with a Statement of Terms and Conditions relating thereto and a Form of Purchase Contract. All bids, whether from a single bidder or a group of bidders, must be for the purchase of all of the Bonds and must be on the Form of Proposal provided by Applicant, signed by the bidder, or by the representative in the case of a group of bidders. Each bid must specify the interest rate to be borne by the Bonds, which rate shall be a multiple of ⅛th of 1 percent; the price exclusive of accrued interest to be paid to Applicant for the Bonds, which price shall be not less than 99% and not more than 102¾% of the principal amount thereof; and, that Applicant shall be paid the amount of the accrued interest on the Bonds from June 1, 1962, to the date of payment therefor and delivery thereof.

Unless postponed, all bids for the purchase of the proposed issuance of Bonds must be presented to Applicant at Room 1100, 231 South LaSalle Street, Chicago 4, Illinois, at or before 10:00 a.m., CDST on June 12, 1962. Applicant, unless it rejects all bids, which it reserves the right to do, or excludes a bid or bids for reasons specified in the Statement of Terms and Conditions, will accept the bid which provides the lowest cost of money to Applicant. Each bid must be accompanied by a certified or bank cashier's check or checks, payable in Chicago or New York Clearing House funds, in the aggregate amount of $450,000.

Applicant states that the proceeds from the sale of the new Bonds will be added to Applicant's general funds and used to pay for a portion of Applicant's 1962 construction program, estimated to cost $39,340,000. The principal items of expenditure for Applicant's 1962 construction program are described, as follows: $5,638,000 for electric generating facilities, including $3,876,000 as Applicant's contribution to research and development costs of a 66,000 kw atomic power plant near Sioux Falls, South Dakota and $1,446,000 for continuing installation of the 200,000 kw Unit #8 at Applicant's Riverside steam electric generating plant in Minneapolis; $9,043,000 for electric transmission lines, including $1,539,000 for continuing construction of a 230 kv interconnection with Minneapolis Power & Light Company and $669,000 for construction of 115 kv

interconnections with Otter Tail Power Company and Minnesota Power & Light Company; $12,974,000 for electric distribution facilities; $2,182,000 for rebuilding steam heating plant, mains and feeder line in St. Paul; $6,943,000 for additions and improvements to propane gas plant and natural gas distribution facilities; and $2,560,000 for additions and improvements to telephone and general utility plant.

Written notice of the application has been given to the Minnesota Railroad and Warehouse Commission, the North Dakota Public Service Commission, and the South Dakota Public Utilities Commission, and to the Governor of each of those States. Notice has also been given by publication in the Federal Register on May 8, 1962 (27 F.R. 4400), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before May 22, 1962 with the Federal Power Commission, Washington 25, D.C. No protest, petition or request to be heard in opposition to the granting of the application has been received.

The Commission finds:

(1) Applicant, a corporation, is a public utility within the meaning of Section 204 of the Federal Power Act, subject to the jurisdiction of the Commission as heretofore described and set forth in the Commission's order issued September 1, 1955, *In the Matter of Northern States Power Company*, Docket No. E-6637 (14 FPC 946).

(2) The proposed issuance and sale of Bonds, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204(f) of the Act; and the proposed issuance of securities is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purposes.

(5) The period of public notice given in this matter is reasonable.

The Commission orders:

(A) The proposed issuance and sale of Bonds, upon the terms and conditions and for the purposes specified in the application, as described above, are authorized, subject to the provisions of this order.

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

(C) This authorization shall expire unless the transaction hereby authorized is consummated within 90 days from the date of issuance of this order.

(D) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(E) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States with respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

CITY OF SEATTLE, WASHINGTON, PROJECT NO. 553

ORDER APPROVING EXHIBIT L DRAWING

(Issued May 24, 1962)

On April 16, 1962, City of Seattle, Washington, licensee for major Project No. 553, filed for Commission approval an Exhibit L drawing which, if approved, would authorize the construction of a minor diversion tunnel extending from Happy Creek to the project reservoir, known as Ross Lake.

The project is situated on Skagit River, County of Whatcom, State of Washington, and affects lands of the United States within the Mt. Baker National Forest. The proposed diversion is within the Mt. Baker National Forest.

Happy Creek now discharges its flow into the Skagit River below the Ross dam and reservoir. The plan for diversion of Happy Creek consists of a small unlined tunnel about 500 feet long, about 4 feet wide and 7 feet high, extending from Happy Creek to a ditch about 60 feet long and 10 feet wide, discharging into Ross Lake. According to the licensee's April 12, 1962 letter transmitting the drawing, the licensee estimates the diversion will result in an increase in the average annual energy generated at the Ross power plant of 1,540,000 kwhs with an annual value of approximately $3,800. The cost of the diversion based on bids will be $38,760. The licensee further estimates that the diversion will pay out in 16 years based on a cost of money of 4 percent.

The proposed diversion will act also as a means of diverting Happy Creek during the raising of Ross dam in the future, and constitutes a further step in the comprehensive development of Skagit River.

The Chief, Forest Service, by letter dated May 8, 1962, has stated that the proposed diversion is not incompatible with the purpose for which Mt. Baker National Forest was created or acquired and that the present terms and conditions of the license for the project are adequate.

The Commission finds:

The afore-mentioned Exhibit L drawing described as Exhibit L, Sheet R-399 (FPC No. 553-195) entitled "Happy Creek-Ross Lake Diversion Tunnel" conforms to the Commission's rules and regulations and should be approved as part of the license for the project.

The Commission orders:

The Exhibit L drawing described in the above finding is approved as part of the license for Project No. 553.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

AREA RATE PROCEEDING, DOCKET NO. AR61-2; ALLADIN EXPLORATION COMPANY, INC., *ET AL.*, DOCKET NO. CI61-1564, *ET AL.*; AMERADA PETROLEUM CORPORATION, *ET AL.*, DOCKET NO. RI60-18, *ET AL.*

ORDER REQUIRING THAT CERTAIN DATA BE FILED, DIRECTING THAT SAID DATA BE PLACED IN PROPER FORM AND PRESENTED IN EVIDENCE

(Issued May 25, 1962)

These proceedings were instituted by our order of May 10, 1961, to determine the initial rates which the public convenience and necessity requires and the just and reasonable rates for sales, subject to our jurisdiction, of natural gas produced in the Southern Louisiana area. Following a prehearing conference and the filing of the examiner's report thereon, we issued our order of November 9, 1961, in which, among other things, it was determined that a single hearing should be held to determine both the initial producer area rate or rates required by the public convenience and necessity and the just and reasonable area rate or rates. In that order the respondents in these proceedings were advised that we would require submission by producers of economic and cost data along the line established by Appendices "A" and "B" (as revised) to our order of August 2, 1961, in Docket No. AR61-1. The same 1960 detail test year as in AR61-1 was to be used. The parties were also put on notice to begin the collection of the necessary data which would be required.

After considering the comments which were submitted respecting the forms and instructions used in Docket No. AR61-1, the Appendix "B" type forms were revised and are now ready for issuance together with instructions which have been expanded and clarified. Much of the data required has already been accumulated by many of the parties who are also respondents in Docket No. AR61-1, and presumably all of the parties herein have been actively collecting the necessary data since the time they were put on notice to do so in our order on November 9, 1961. Consequently it is considered that a three-month period for the filing of the material would be ample and consistent with the carrying out of the objective to proceed expeditiously herein. However, the filing of Appendix "B" material will not be required of all respondents. Based on our experience in Docket No. AR61-1 only those respondents having company-wide jurisdictional sales of more than 10 million Mcf of natural gas during the year 1960 will be required to file the data required by Appendix "B".

Appendices "A" and "C" as used in Docket No. AR61-1 are under continuing staff study. Upon conclusion of the study and revision of the forms and instructions, the Commission will issue an order in these proceedings, setting forth the procedure to be followed for the filing of the data which may be required by the appendices. Generally the data to be filed will be the same as were required in Docket No. AR61-1.

We are requiring the Commission staff to compile data with respect to each rate schedule on file with the Commission for the jurisdictional sale of gas from the Southern Louisiana area. Following generally the procedure adopted in Docket No. AR61-1, upon completion of the compilation it is intended to forward to each respondent the data compiled respecting such respondents' rate schedules with a request that same be checked for accuracy and certain information be furnished in connection therewith.

The Commission finds:

It is necessary and appropriate in the public interest, and to aid in the enforcement of the provisions of the Natural Gas Act, particularly Sections 4, 5, 7, 8, 10, 14 and 16 thereof, that the respondents herein be required to furnish certain data to the Commission and the Commission staff be directed to compile data, all as hereinafter ordered.

The Commission orders:

(A) All respondents to these consolidated proceedings having company-wide jurisdictional sales of more than 10 million Mcf of natural gas during the year 1960 shall complete and on or before August 24, 1962, shall file with the Secretary of the Commission three copies of the data required by Appendix "B" hereto, on the forms herein prescribed entitled "Costs and Statistics Pertaining to Oil and Gas Production, Exploration, Gas Gathering and Products Extraction Operations, Year 1960".

(B) The data furnished in compliance with paragraph (A) hereof shall be compiled in composite form by the Commission staff for introduction in these proceedings. Such data furnished by the respondents as ordered herein shall not be available to any party other than the Commission or its staff until the data in composite form have been prepared by the staff and distributed to the parties to these proceedings.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross, and Harold C. Woodward.

CITIES SERVICE COMPANY (FORMERLY CALLED ARKANSAS FUEL OIL CORPORATION), DOCKET NO. G–15646; CITIES SERVICE PRODUCTION COMPANY, DOCKET NO. G–15653

ORDER GRANTING EXTENSION OF TIME

(Issued May 28, 1962)

By its order issued March 5, 1962, in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, the Commission disposed of more than 400 proceedings, including those above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. With respect to the above-listed dockets, ordering paragraph (A) of the March 5 order directed Cities Service Company (formerly called Arkansas Fuel Oil Corporation) and Cities Service Production Company (hereinafter called Petitioners), respectively, to refund tax-reimbursement amounts collected from their direct customer United Fuel Gas Company (United Fuel). Ordering paragraph (C) of that order directed that within 90 days from the date of issuance thereof, Petitioners report to the Commission the details of their refund calculations and submit copies of releases from United Fuel with respect to the required refunds. By order issued April 26, 1962 in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, the Commission denied applications for rehearing of the March 5, 1962 order in the above, as well as other, dockets. On May 15, 1962, Petitioners filed a joint and several motion seeking to stay the effectiveness of the March 5 order, insofar as applicable to the above dockets, until a date 30 days after conclusion of judicial review of said order in those dockets. The motion recites that Petitioners intend to seek judicial review of the March 5 order and that failure of the Commission to grant the stay pending such review would cause them irreparable injury.

For reasons stated in our order of April 13, 1962 granting Pan American Petroleum Corporation an extension of time for compliance, we are disposed to extend the time within which Petitoners must comply with ordering paragraphs (A) and (C) of the Commission's March 5 order, for a period ending 30 days after conclusion of judicial review of that order in the instant dockets.[1] The extension is conditional, however, upon the payment by Petitioners to United Fuel of interest at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the order of March 5. In prior orders granting extensions of time in these proceedings,[2] we provided that such extensions should not become operable unless and until the applicant had petitioned for review of the March 5 order, and that if within 90 days after issuance of that order the applicant had neither complied therewith nor petitioned for review, it should be deemed in default. Petitioners have, in effect, requested a waiver of this requirement, advising that their petitions for judicial review could probably not be filed earlier than 60 days after the April 26 order denying rehearing. We are disposed to grant this request. Accordingly, the extensions of time granted herein shall be effective immediately, but shall be deemed inoperative if Petitioners have not petitioned for judicial review within the statutory 60 day period after our April 26 order denying rehearing.

The Commission finds:

(1) There is good cause for extending the time within which Petitioners must comply with the requirements of ordering paragraphs (A) and (C) of our order of March 5, 1962, for a period ending 30 days after the conclusion of judicial review of that order in the instant dockets.

(2) It is just and reasonable and in the public interest that Petitioners be required to pay United Fuel interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the March 5 order.

The Commission orders:

(A) The time within which Petitioners must comply with ordering paragraphs (A) and (C) of the Commission's order of March 5, 1962 is extended for a period ending 30 days after the conclusion of judicial review of the Commission's order of March 5, 1962 in the instant dockets.

(B) Petitioners shall pay United Fuel interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the March 5, 1962 order.

(C) The time within which United Fuel must comply with ordering paragraphs (B) and (D) of the March 5, 1962 order, insofar as applicable to the instant dockets, is extended for a period ending 60 days after conclusion of judicial review of that order in said dockets.

(D) If Petitioners shall not have filed petitions for review of the March 5 order in the instant dockets within the period prescribed by statute, the extension of time herein granted shall be deemed inoperative and of no effect.

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[1] It should be understood that the 30th day after judicial review in the instant dockets is the date upon which Petitioners must comply with the March 5 order; it is *not* the date upon which the 90 day period referred to in ordering paragraph (C) commences to run.

[2] Union Texas Petroleum, Docket Nos. G–15833 and G–16023; Sun Oil Company, Docket No. G–13169.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

MIDWESTERN GAS TRANSMISSION COMPANY, DOCKET NO. RP62-7

ORDER INSTITUTING INVESTIGATION AND PROVIDING FOR HEARING

(Issued May 28, 1962)

Midwestern Gas Transmission Company (Midwestern) was authorized to construct and operate the facilities which currently constitute its Northern System, subject to the terms and conditions set out in Opinion No. 331, and accompanying order issued October 31, 1959, *Midwestern Gas Transmission Company*, Docket Nos. G–18313, *et al.*[1] Among other things, paragraph (D) (iv) of that order required that Midwestern, at the end of one year's operating experience, file with the Commission "revised rate schedules based on the company's operating experience and supporting data" whereby the Commission could determine the propriety of the rate differential reflecting lateral line charge under Midwestern's Rate Schedule CD–1 and the propriety of the relative levels of the demand and commodity components of Midwestern's rate schedules.

On December 29, 1961, Midwestern, by letter, informed the Commission that it proposed to retain in effect the present rate schedules for sales on its Northern System and therewith filed certain cost data purporting to support the presently effective rates.

The Commission finds:

(1) Midwestern's tender of December 29, 1961 does not appear to meet the requirements imposed by Opinion 331, issued October 31, 1959 in Docket No. G–18313, *et al.*

(2) It is necessary and proper in the public interest and to aid in the enforcement of the provisions of the Natural Gas Act that an investigation be instituted by the Commission, upon its own motion, into and concerning the rates, charges, or classifications demanded, charged, or collected by Midwestern for or in connection with any transportation or sale of natural gas subject to the jurisdiction of the Commission, and any rules, regulations, practices, or contracts affecting such rates, charges or classifications.

The Commission orders:

(A) An investigation of Midwestern be and it hereby is instituted under the provisions of the Natural Gas Act, for the purpose of enabling the Commission to determine with respect to Midwestern's operations, whether in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, any rates, charges, or classifications demanded, observed, charged, or collected, or any rules, regulations, or contracts affecting such rates, charges, or classifications are unjust, unreasonable, unduly discriminatory, or preferential.

(B) If after hearing has been had, the Commission finds that any rates, charges, or classifications, rules, regulations, practices, or contracts applicable to Midwestern's operations in its Northern System are unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall thereupon determine, fix and prescribe by appropriate order or orders, just, reasonable, non-dis-

[1] Opinion No. 331 (22 FPC 775), was modified by orders issued December 29, 1959 (22 FPC 1157) and January 20, 1960 (23 FPC 111), but such modifications are not material to this order.

criminatory, and non-preferential rates, charges, classifications, rules, regulations, practices, or contracts to be thereafter observed and in force in Midwestern's Northern System.

(C) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Power Commission by the Natural Gas Act, particularly Sections 5, 14, 15 and 16 thereof, and the Commission's Rules of Practice and Procedure, a public hearing be held at a date later to be designated by notice from the Secretary of the Commission in a hearing room of the Commission at 441 G Street, N.W., Washington 25, D.C., concerning the matters specified in paragraph (A) above.

(D) Notices of intervention or petitions to intervene may be filed with the Federal Power Commission, Washington 25, D.C., in accordance with the Commission's Rules of Practice and Procedure [18 CFR 1.8 and 1.37(f)] on or before June 22, 1962.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NATURAL GAS PIPELINE COMPANY OF AMERICA, DOCKET NOS. G–18148, G–18149, AND RP60–5

ORDER AMENDING ORDER APPROVING SETTLEMENT AGREEMENTS

(Issued May 28, 1962)*

On November 24, 1961, the Commission issued an Order Approving Proposed Settlement Agreements, As Conditioned, And Prescribing Interim Refunds in the above docketed proceedings relating to Natural Gas Pipeline Company of America (Natural). Paragraph (E)(IV) of that order stated as follows:

> (IV) In the event that the staff, upon completion of its field examination of the books and records of Natural for the locked-in period of time involved in these proceedings, shall conclude that items of cost of service, included in the settlement computations but in addition to and separate from the matters referred to in sub-paragraphs (II) and (III), above, are not acceptable, then, after conference, hearing and further order of the Commission, as necessary to a resolution of this matter, Natural shall be required to make such further refunds in these proceedings, with interest at 6% thereon, as may result from a consideration of such items of cost of service.

A question arising out of Natural's cost of service study involved the depreciation of transmission rights-of-way for which Natural made deductions in its tax filing and which deductions the Internal Revenue Service is at present contesting, notwithstanding the allowance of such deductions by the Court of Appeals in a purportedly similar situation.[1] In the settlement study Natural computed its taxes as though the deductions in question were not allowable, and the above quoted paragraph from the Commission's order was directed to Natural's obligations in the event that the IRS determine the tax amounts in question to be excludable.

The Commission staff conducted an investigation and upon completing its examination of Natural's books and records for the period of time involved concluded that Natural's cost of service reflecting certain amounts for claimed income taxes but which Natural was in fact contesting was overstated in the

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*Modified; rehearing denied by order issued July 27, 1962, 28 FPC 233.

[1] *Northern Natural Gas Company* v. *O'Malley*, 277 F. 2d 128 (USCA 8).

amount of whatever reduction of Natural's tax liabilities the Internal Revenue Service should subsequently allow. Accordingly, by letter dated February 20, 1962, the Commission notified Natural that the settlement agreement referred to hereininabove should be modified to reflect the findings of Commission staff described. On March 5, 1962, Natural filed a letter accepting the conditions set forth in the Commission's letter, and requested, however, that it be exempted from interest obligation regarding such refunds as it may ultimately be required to make.

The Commission finds:

It is appropriate in view of the findings referred to above that in the event the Internal Revenue Service allows the depreciation of transmission rights-of-way as a proper expense in the computation of Natural's income tax for the period covered by the proceedings in the above dockets, Natural should refund in the manner prescribed by the Commission in paragraph (E) (IV) of the order issued November 24, 1961, such amounts as are indicated by a recomputation of Natural's income taxes for the periods involved, based upon the deduction of such depreciation. Further, it does not appear that Natural has shown good cause why such refunds should not include interest at 6% per annum on all amounts refunded as prescribed by said paragraph and as is consistent with the Commission's practice and the provisions of the Natural Gas Act.

The Commission orders:

(A) Natural shall refund all amounts, together with interest thereon at 6% per annum, as are indicated by a recomputation of the income tax allowance in its cost of service relating to the proceedings in Docket Nos. G–18148, G–18149, and RP60–5, such recomputation to be made upon a determination of the Internal Revenue Service that the depreciation of transmission right-of-way is an allowable expense for purposes of computing income taxes.

(B) All refunds as ordered above shall be made in accordance with the provisions of the Commission's order issued November 24, 1961.

(C) In all other respects this order of the Commission issued November 24, 1961, shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

SENECA GAS COMPANY OF WEST VIRGINIA, INC., DOCKET NO. G–18442; ATLANTIC SEABOARD CORPORATION, DOCKET NO. CP62–67; SENECA GAS COMPANY OF WEST VIRGINIA, INC., COMPLAINANT *v.* NAVGAS, INC., DEFENDANT, DOCKET NO. CP62–115; NAVGAS, INC., DOCKET NO. CP61–251

FINDINGS AND ORDER DISMISSING APPLICATION AND COMPLAINT AND ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued May 28, 1962)

On April 30, 1959, Seneca Gas Company of West Virginia, Inc. (Seneca), a West Virginia corporation having its principal office in Winchester, Virginia, filed an application in Docket No. G–18442, and on June 1, 1959, a supplement thereto, pursuant to Section 7(a) of the Natural Gas Act, for an order directing Atlantic Seaboard Corporation (Seaboard) to establish physical connection of its transportation facilities with the facilities which Seneca proposed to construct

and to sell and deliver to Seneca its natural gas requirements for resale to the United States Navy and public in Hardy and Pendleton Counties, West Virginia.

Seneca proposed to construct and operate approximately 24 miles of 6⅝-inch transmission pipeline extending from a connection with Seaboard's 26-inch transmission line at a point west of Mathias in Hardy County, West Virginia to the site of the Naval Radio Research Observatory at Sugar Grove, Pendleton County, West Virginia. Seneca alleged it planned to construct and operate a natural gas distribution system to serve the Naval facility near Sugar Grove and to serve other customers and unincorporated towns and villages along the route of the proposed transmission line.

Seneca estimated its fifth year gas requirements for the area it proposed to serve as follows: peak day, 1,050 Mcf, annual, 600,000 Mcf.

More than 90 percent of the annual volumes, and 40 to 60 percent of the peak day volumes were proposed to be utilized by the U.S. Naval Radio Research Station.

Seneca estimated the cost of its project would be $783,280.

Seneca alleged that it had been granted a certificate of public convenience and necessity by the Public Service Commission of West Virginia to construct and operate natural gas transmission distribution facilities in Hardy and Pendleton Counties.

Notice of Seneca's said application was issued by the Secretary of the Commission on December 2, 1959, and published in the Federal Register on December 8, 1959 (24 FR 9918) together with notice of hearing to commence on January 11, 1960. By notice of the Secretary of the Commission issued January 7, 1960, and published in the Federal Register on January 14, 1960 (25 FR 320), said hearing was continued, subject to further notice by the Secretary.

On March 22, 1961, Navgas, Inc. (Navgas) filed an application, in Docket No. CP61–251, pursuant to Section 7(a) of the Act, for an order directing Seaboard to establish physical connection of its transportation facilities with the facilities proposed to be constructed by Navgas and to sell and deliver to Navgas its natural gas requirements for service to the Naval Radio Research Station near Sugar Grove, West Virginia. On March 16, 1962, Navgas filed an amendment to said application in Docket No. CP61–251 requesting, in lieu of relief under Section 7(a) of the Act, a finding and order that no certificate is required, or in the alternative, an order issuing a certificate of public convenience and necessity pursuant to Section 7(c) of the Act, authorizing the construction and operation of approximately 24.2 miles of 6⅝ inch pipeline and appurtenant facilities from a point of connection with the facilities of Seaboard in Hardy County, West Virginia, to the Naval Radio Research Station, near Sugar Grove, West Virginia, for the purpose of delivery and sale of natural gas to said station.

On September 15, 1961, Seaboard filed an application in Docket No. CP62–67, pursuant to Section 7(c) of the Act, for a certificate of public convenience and necessity authorizing the construction and operation of measuring and regulating facilities for the delivery and sale of natural gas to Navgas, Inc., a new customer, to permit Navgas, Inc., to render service to said Naval Radio Research Station.

Seneca filed on November 3, 1961, in Docket No. CP62–115 a complaint against Navgas, Inc., alleging, *inter alia*, that Navgas, Inc., is not exempt from the provisions of the Natural Gas Act by virtue of Section 1(c) thereof because Navgas, Inc.'s proposed rates and service are not regulated by the Public Service Commission of West Virginia. Seneca alleged further that Navgas, Inc., was then in the process of constructing facilities for the purpose of engaging in the transportation and sale of natural gas to the Navy, and, in so proceeding, Navgas, Inc., had violated the Natural Gas Act in that it had neither made application

with nor been granted a certificate of public convenience and necessity by this Commission, authorizing said construction.

Notice of the application in Docket No. CP62–67, and the complaint in Docket No. CP62–115 was issued by the Acting Secretary of the Commission on February 2, 1962, and published in the Federal Register on February 9, 1962 (27 FR 1232), setting said matters, including the application of Seneca in Docket No. G–18442, for consolidated hearing on a consolidated record for April 9, 1962.

Notice of the application in Docket No. CP61–251 was issued by the Acting Secretary of the Commission on March 21, 1962, and published in the Federal Register on March 27, 1962 (27 FR 2819), setting said docket for consolidated hearing on a consolidated record with Docket Nos. G–18442, CP62–67 and CP62–115, for April 9, 1962.

By notice issued by the Secretary of the Commission on March 29, 1962, and published in the Federal Register on April 4, 1962 (27 FR 3216), the hearing date for all the aforesaid consolidated dockets was postponed from April 9, 1962, to April 16, 1962.

By order issued April 9, 1962, Seneca was permitted to intervene in Docket No. CP61–251; the United States Department of the Navy, acting through the Chief of the Bureau of Yards and Docks, was permitted to intervene in Docket Nos. G–18442, CP62–67 and CP62–115; and Navgas, Inc. was permitted to intervene in each of the Docket Nos. G–18442, CP62–67 and CP62–115. By order issued January 15, 1960, Blue Ridge Gas Company was permitted to intervene in Docket No. G–18442.

Pursuant to the aforesaid notice of hearing, all the aforesaid consolidated matters came on for hearing before the Chief Presiding Examiner of the Commission on April 16, 1962. Neither any officer nor any representative of Seneca appeared at said hearing. The Chief Presiding Examiner read into the record a telegram from an officer of Seneca received by the Commission on the morning of said April 16, 1962, requesting a general continuance without a date named. The United States Navy Department, Navgas and Seaboard proceeded with the introduction of evidence in support of the applications of Navgas and Seaboard.

The undisputed evidence from witnesses on behalf of the Navy discloses that the U.S. Navy is constructing a Naval Radio Research Station near the town of Sugar Grove, West Virginia.

The Navy estimates that its annual requirements will be 549,000 Mcf and its peak day demand will be 2,000 Mcf. Since the area is sparsely settled, the Navy will construct support facilities at the Station, and natural gas will also be used at such facilities for cooking, water heating, space heating and similar uses.

The evidence on behalf of Navgas shows that it has a contract with the Department of the Navy (United States of America) dated as of June 15, 1960, to supply the natural gas requirements for the Naval Radio Research Station at Sugar Grove, West Virginia under the terms and conditions therein set forth.

The evidence further shows that on a complaint filed by Seneca against Navgas before the Public Service Commission of West Virginia, the West Virginia Commission found and concluded that Navgas in serving the Navy only and no other customers is not a public utility subject to the jurisdiction of the Public Service Commission of West Virginia and dismissed the complaint of Seneca against Navgas for lack of jurisdiction (*Seneca Gas Co. of W. Va., Inc.* v. *Navgas, Inc.*, Case No. 5169, order issued March 17, 1961). On appeal to the Supreme Court of Appeals of West Virginia, that Court sustained the West Virginia Commission and denied the appeal. *Seneca Gas Company of West Virginia, Inc.* v. *The Public Service Commission of West Virginia*, order issued June 19, 1961 (W. Va. Sup. Ct. of Appeals).

Navgas has constructed 24.6 miles of 6⅝-inch pipeline from a point of connection on Seaboard's main 26-inch pipeline in Hardy County, West Virginia southerly to Navgas' meter-regulator station, approximately 5,000 feet northeast of the United States Navy's electric generating plant at the Naval Radio Research Station near Sugar Grove, West Virginia. This line is not in operation, but one of the Navy's witnesses testified that the Navy would like to be able to use natural gas on November 1, 1962, when the power plant is completed.

The 24.6 miles of pipeline constructed by Navgas has sufficient capacity under the pressures indicated on the flow diagram (Exhibit 6) to deliver the required peak day volume of gas to the Naval Radio Research Station. There is no question as to the adequacy of Navgas' supply of gas, which will be received from Seaboard.

The total overall cost of the facilities constructed and to be constructed is $794,590, to be financed by temporary bank loans. The Navy is obligated to provide $650,000 as a connection charge, which, in turn will be refunded by equal monthly repayments over a twenty-year period. The evidence shows that the revenues received from the Navy will be sufficient to pay the operating expenses of Navgas, including cost of purchased gas[1] and depreciation.

Seaboard's evidence in Docket No. CP62–67 shows that Seaboard is a subsidiary of Columbia Gas System, Inc. and that it seeks to serve Navgas the natural gas requirements for said Naval Radio Research Station. Seaboard has sufficient capacity in its system at the point of interconnection with Navgas' facilities to serve the aforesaid peak day and annual requirements. The only facilities to be constructed by Seaboard consist of measuring and regulating facilities estimated to cost $19,600.

The evidence shows that the sale and delivery of natural gas to the Naval Radio Research Station will be a direct sale by Navgas, Inc. pursuant to the contract between the United States of America and Navgas, Inc. and that this sale will be the only sale and delivery made by Navgas Inc. The entire transmission line of Navgas is situated within the State of West Virginia.

With reference to the construction of facilities prior to obtaining a certificate, the President of Navgas testified that the Navy Department insisted that the construction of the pipeline take place as soon as possible, and the contract between the parties provided that Navgas proceed with construction in accordance with the time schedule therein set forth. In view of the relation of the Naval Radio Research Station to the national defense, and the then pending proceedings in West Virginia on the determination of the status of Navgas, he stated that there was no intent on the part of Navgas or any of its officers or employees willfully and knowingly to violate the provisions of the Natural Gas Act.

Navgas was in a no-man's land so far as its jurisdictional status was concerned pending final determination by the West Virginia authorities, since if West Virginia asserted jurisdiction, Navgas would be exempted from this Commission's jurisdiction under Section 1(c) of the Act, the witnsss said. Upon final disposition by the West Virginia Commission and Court, holding that Navgas is not a public utility subject to the jurisdiction of the West Virginia Public Service Commission, Navgas amended its original Section 7(a) application before us in the manner heretofore indicated.

At the conclusion of the hearing, counsel for Navgas, Inc. moved orally on the record that the intermediate decision procedure be omitted, and that the Commission forthwith render a decision herein pursuant to Section 1.30(c)(1) of

[1] Computations based upon Seaboard's currently effective tariff of $3.00 per Mcf, demand charge and 29.91 cents per Mcf, commodity charge.

the Commission's Rules of Practice and Procedure. All counsel present, including Staff Counsel, concurred in said motion. All parties waived the filing of briefs and, in lieu thereof, the Chief Presiding Examiner fixed May 14, 1962, as the date for the submission of the order herein.

On May 4, 1962, the Commission issued an order denying Seneca's request for a continuance. In said order we pointed out that from Seneca's application, it appears that more than 90 percent of the annual volumes and 40 to 60 percent of the peak day volumes of the estimated requirements of Seneca were proposed to be utilized to supply gas service for the United States Naval Radio Research Station, Sugar Grove, West Virginia.

We also set forth the situation relating to Seneca's application as follows: The Department of the Navy advised the Commission, by letter dated December 14, 1959, that due to the number and complexity of the proposals to supply gas service for said naval facility, it did not appear that any decision would be reached as to the selection of a company and negotiation of a contract for service by January 11, 1960. On December 30, 1960, the Commission addressed a letter to Counsel for Seneca stating in substance that in view of the fact that the Navy had not yet awarded a contract for furnishing gas service, it appeared appropriate to continue the hearing then set for January 11, 1960, until a contract had been awarded. Accordingly, on January 7, 1960, said hearing was continued subject to further notice by the Secretary.

By letter dated September 29, 1960, the Department of the Navy, Bureau of Yards and Docks, advised the Commission that on June 15, 1960, a contract for natural gas service to its said radio research station was awarded to Navgas, Inc., Charleston, West Virginia, and that a contract was then being finalized for execution by the parties. In view thereof, the Department of the Navy wrote, an allocation of gas to Seneca, as required by Seneca, in order to provide service to the said Naval Radio Research Station, was no longer required. On October 11, 1960, the Commission addressed a letter to Seneca pointing out that Seneca's application for a Section 7(a) order in Docket No. G–18442 indicated that the feasibility of its project depended directly on revenues to be derived from the sale of natural gas to the Naval Research Station at Sugar Grove, and suggesting that Seneca review its proposal, and, if it was determined that the matter should not be further prosecuted, that Seneca consider withdrawal of its application. No action was taken by Seneca.

The Commission finds:

(1) Seneca Gas Company of West Virginia, Inc., applicant in Docket No. G–18442, and complainant in Docket No. CP62–115, not appearing at the regularly scheduled and properly noticed hearing, its application in said Docket No. G–18442 and complaint in said Docket No. CP62–115 should be dismissed.

(2) Atlantic Seaboard Corporation, a Delaware corporation, having its principal place of business at Charleston, West Virginia, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of March 16, 1943, in Docket No. G–284 (3 FPC 941).

(3) Navgas, Inc., a West Virginia corporation, having its principal place of business at Charleston, West Virginia, not being subject to the jurisdiction of the West Virginia Public Service Commission, upon commencement of the transportation and sale of gas for which certificate authorization is requested herein will be engaged in the transportation of natural gas in interstate commerce, and will become a "natural-gas company" within the meaning of the Natural Gas Act.

(4) The facilities which Seaboard and Navgas propose to construct and operate, as described in their respective applications, for the sale and transportation of natural gas in interstate commerce, respectively, are subject to the jurisdiction of the Commission, and therefore, subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) The aforesaid proposed construction and operation of the facilities by Atlantic Seaboard Corporation, together with the proposed sale and transportation of natural gas, subject to the jurisdiction of the Commission, are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(6) The proposed operation of the facilities constructed by Navgas, Inc., is required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(7) Applicants, Seaboard and Navgas, are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(8) Public convenience and necessity require that the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.20) should apply to the certificates issued hereinafter and to the exercise of the rights granted thereunder.

(9) A request during the public hearing by counsel for Navgas, Inc. for omission of the intermediate decision procedure, and all requirements of Section 1.30(c)(1) [(18 CFR 1.30(c)(1))] of the Commission's Rules of Practice and Procedure having been satisfied, sufficient cause exists for the Commission to render its final decision in the instant proceeding.

The Commission orders:

(A) The application of Seneca Gas Company of West Virginia, Inc., in Docket No. G–18442, and the complaint filed by Seneca Gas Company of West Virginia, Inc. against Navgas, Inc., in Docket No. CP62–115 be and the same are each hereby dismissed.

(B) A certificate of public convenience and necessity be and the same is hereby issued to Atlantic Seaboard Corporation, authorizing the construction and operation of the natural gas facilities for the sale and transportation of natural gas, as described in the application in Docket No. CP62–67, upon the terms and conditions of this order.

(C) A certificate of public convenience and necessity be and the same is hereby issued to Navgas, Inc., authorizing the operation of the facilities constructed by Navgas, Inc., as described in the application in Docket No. CP61–251, upon the terms and conditions of this order.

(D) The general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act shall attach to the issuance of the certificates granted herein and to the exercise of the rights thereunder.

(E) The time within which the facilities hereby authorized shall be constructed and placed in actual operation as provided by paragraph (b) of said Section 157.20 of the Commission's Regulations is hereby fixed at twelve (12) months from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

UNION OIL COMPANY OF CALIFORNIA, DOCKETS NOS. G–15846, G–15847, AND G–16074

ORDER GRANTING EXTENSION OF TIME

(Issued May 28, 1962)

By its order issued March 5, 1962, in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, 27 FPC 441, the Commission disposed of more than 400 proceedings, including those above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. With respect to Docket No. G–15846, ordering paragraph (A) of the March 5 order directed Union Oil Company of California (Union) to refund tax-reimbursement amounts collected from its direct customer United Fuel Gas Company (United Fuel). With respect to Docket No. G–15847, said paragraph required Union to make such refund to Transcontinental Gas Pipe Line Corporation (Transco), Texas Gas Transmission Corporation (Texas Gas), and United Fuel.[1] Ordering paragraph (C) of the March 5 order directed that within 90 days from the date of issuance thereof, Union report to the Commission the details of its refund calculations and submit copies of releases from Transco, Texas Gas, and United Fuel as to the required refunds. By order issued April 26, 1962 in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, the Commission denied applications for rehearing of the March 5 order in the above, as well as other, dockets. On May 18, 1962 Union filed a motion seeking to stay the effectiveness of the March 5 order, insofar as applicable to the above dockets, and requesting an extension of time for compliance therewith, for a period ending 30 days after conclusion of judicial review of said order in those dockets. The motion recites that Union intends to seek judicial review of the March 5 order and that failure of the Commission to grant the stay pending such review would cause it irreparable injury.

For reasons stated in our order of April 13, 1962 granting Pan American Petroleum Corporation an extension of time for compliance,[2] we are disposed to extend the time within which Union must comply with ordering paragraphs (A) and (C) of the Commission's March 5 order, for a period ending 30 days after conclusion of judicial review of that order in the instant dockets. The extension is conditional, however, upon the payment by Union to Transco, Texas Gas, and United Fuel of interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the order of March 5.

The Commission finds:

(1) There is good cause for extending the time within which Union must comply with the requirements of ordering paragraphs (A) and (C) of our order of March 5, 1962, for a period ending 30 days after conclusion of judicial review of that order in the instant dockets.

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[1] In Docket No. G–16074, no refunds were ordered. Accordingly, the motion for stay and extension of time herein considered shall be deemed applicable only to Docket Nos. G–15846 and G–15847.

[2] Pan American Petroleum Corporation, Docket No. G–15641; Pan American Petroleum Corporation (Operator), *et al.*, Docket Nos. G–15650 and G–15780.

(2) It is just and reasonable and in the public interest that Union be required to pay Transco, Texas Gas and United Fuel interest, at a rate of 7% upon the amounts to be refunded, for the period commencing on the 91st day after issuance of the March 5 order.

The Commission orders:

(A) The time within which Union must comply with ordering paragraphs (A) and (C) of the Commission's order of March 5, 1962 is extended for a period ending 30 days after the conclusion of judicial review of the Commission's order.

(B) Union shall pay Transco, Texas Gas and United Fuel interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the March 5, 1962 order.

(C) The time within which Transco, Texas Gas, and United Fuel must comply with ordering paragraphs (B) and (D) of the March 5, 1962 order, insofar as applicable to the instant dockets, is extended for a period ending 60 days after conclusion of judicial review of that order in said dockets.

(D) If Union shall not have filed petitions for review of the March 5 order in the instant dockets within the 60 day period prescribed by statute, the extension of time herein granted shall be deemed inoperative and of no effect.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

THE BRADLEY PRODUCING CORPORATION, DOCKET NO. G-19401; TEXACO INC., DOCKET NO. CI62-335 [1]

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY, ACCEPTING RELATED FPC GAS RATE SCHEDULES, AMENDING PRIOR CERTIFICATE ORDERS, AND CANCELLING DOCKET NUMBER

(Issued May 29, 1962)[2]

Each of the above Applicants has filed an application pursuant to Section 7 (c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the sale and delivery of natural gas in interstate commerce as hereinafter described, all as more fully described in the respective applications (and any supplements or amendments thereto) which are on file with the Commission and open to public inspection.

The Applicants herein produce and propose to sell natural gas for transportation in interstate commerce for resale as indicated below:

Docket No.	Field and Location	Purchaser
CI62-335	Carter-Knox Field, Stephens County, Okla.	Lone Star Gas Co.[3]

Each Applicant in this consolidated proceeding has filed a related rate schedule for the proposed service. Such Applicants have been advised of the acceptance and designation of these related rate filings with the exception of the Applicants in Docket Nos. CI62-117 and CI62-170 whose related rate schedules are accepted hereinafter. None of the proposed rates exceeds the announced ceiling rates for the respective areas involved.

[1] Remaining applicants and docket numbers omitted in printing.

[2] Letter-order issued July 27, 1962 dismissing application for rehearing, 28 FPC 236. Petition for Review dismissed, *Texaco Inc.* v. *F.P.C.*, 317 F. 2d 796 (CA10-1963).

[3] Remaining purchasers, fields, etc., omitted in printing.

Austin Brady proposes in Docket No. G–20264 to sell natural gas from the W. H. Robinson Leases, Section 14, T28S, R32W, Haskell County, Kansas, (to certain depths), acquired by assignment from The Cooperative Refinery Association, which Association received certificate authorization in Docket No. G–9650 (Docket Nos. G–9650, *et al.*) covering said acreage, *inter alia.*

Braden Drilling, Inc. proposes in Docket No. G–20294 to sell natural gas from the Robbins and Irwin Leases, SE/4 of Section 21 and SW/4 of Section 14, respectively, T27S, R15W, Pratt County, Texas, acquired by assignment from Tatlock Oil Company, which Company received certificate authorization in Docket No. G–17858 (Docket Nos. G–11495, *et al.*) covering said acreage, *inter alia.*

Bonray Oil Company proposes in Docket No. CI60–306 to sell natural gas from the NE/4 of Section 7, T28N, R8W, Grant County, Oklahoma, acquired by assignment from Viersen & Cochran who received certificate authorization in Docket No. G–10690 (Docket Nos. G–10934, *et al.*) covering said acreage, *inter alia.*

Tower Oil & Gas Company of Texas proposes in Docket No. CI60–665 to sell natural gas from the Lela Hill Lease, SE/4, Section 31, Block D of the E.L. & R.R. RY. Co. Survey, Upton County, Texas, acquired by assignment from Hunt Oil Company, successor to Rutter and Wilbanks Brothers, Operator, who received certificate authorization in Docket No. G–8002 covering said acreage, *inter alia.*

Glen A. Martin (Operator), *et al.* propose in Docket No. CI61–1013 to sell natural gas from the P. H. Breeden Lease covering a portion of the Jos. Simons 1/3 League, Goliad County, Texas, to depths between the top of the Reklaw Sand Formation and 8,362 feet, acquired by assignment from Sunray Mid-Continent Oil Company, which Company received certificate authorization in Docket No. G–4948 (Docket Nos. G–2975, *et al.*) covering said acreage, *inter alia.*

The application of Graham-Michaelis Drilling Company (Operator), *et al.* in Docket No. CI62–179 covers additional acreage pursuant to an amendatory agreement to the basic contract between Graham-Michaelis and Northern Natural Gas Company for which certificate authorization was originally granted in Docket No. G–11570, hence the subject application will be treated as an application to amend said authorization in Docket No. G–11570 and the docket designation No. CI62–179 will be cancelled.

Pursuant to due notice, a public hearing was held in Washington, D.C. on May 10, 1962, respecting the matters involved in and the issues presented by the respective applications herein. No petition to intervene or protest to the granting of any of said applications has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules and Practice and Procedure.

The Commission finds:

(1) Each Applicant herein is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission, or will be engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission, and will, therefore, be a "natural-gas company" within the meaning of said Act upon the commencement of the service under the respective authorizations granted hereinafter.

(2) The sales of natural gas hereinbefore described, as more fully described in the respective applications, and any amendments and/or supplements thereto, will be made in interstate commerce, subject to the jurisdiction of the Commission, and such sales by the respective Applicants, together with the construction and operation of any facilities subject to the jurisdiction of the

Commission necessary therefor, are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) The sales of natural gas by the respective Applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(4) The respective Applicants herein are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(5) The orders of the Commission granting certificates of public convenience and necessity to The Cooperative Refinery Association, Tatlock Oil Company, Viersen & Cochran, Hunt Oil Company and Sunray Mid-Continent Oil Company in Docket Nos. G–9650, G–17858, G–10690, G–8002 and G–4948, respectively, should be amended by deleting therefrom certain authorization as hereinafter ordered.

(6) The order of the Commission granting a certificate of public convenience and necessity to Graham-Michaelis Drilling Company (Operator), *et al.* in Docket No. G–11570 should be amended by adding thereto certain authorization as hereinafter ordered.

(7) The docket designation, Docket No. CI62–179, should be cancelled as hereinafter ordered.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Certificates of public convenience and necessity be and the same are hereby issued, upon the terms and conditions of this order, authorizing the sales by the respective Applicants herein of natural gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary for such sales, all as hereinbefore described and as more fully described in the respective applications, and any amendments and/or supplements thereto, in this proceeding.

(B) The certificates granted in paragraph (A) above are not transferable and shall be effective only so long as Applicants continue the acts or operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations and orders of the Commission.

(C) The grant of the certificates issued in paragraph (A) above shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or of Part 154 or Part 157 of the Commission's Regulations thereunder, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the respective Applicants. Further, our action in this proceeding shall not foreclose nor prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contracts herein involved. Nor shall the grant of the certificates aforesaid for service to the particular customers involved imply approval of all of the terms of the respect' e contracts, particularly as to the cessation of service upon termination of said contracts, as provided by Section 7(b) of the Natural Gas Act. Nor shall the grant of the certificates aforesaid be construed to preclude the

imposition of any sanctions pursuant to the provisions of the Natural Gas Act for the unauthorized commencement of any sales of natural gas subject to said certificates.

(D) The orders of the Commission granting certificates of public convenience and necessity to The Cooperative Refinery Association, Tatlock Oil Company, Viersen & Cochran, Hunt Oil Company and Sunray Mid-Continent Oil Company in Docket Nos. G–9650, G–17858, G–10690, G–8002 and G–4948, respectively, are hereby amended by deleting therefrom so much of the authorization for the sale of natural gas as is the subject of the instant applications in Docket Nos. G–20284, G–20294, CI60–306, CI60–665 and CI61–1013, respectively, as more particularly set forth hereinabove.

(E) The order of the Commission granting a certificate of public convenience and necessity to Graham-Michaelis Drilling Company (Operator), *et al.* in Docket No. G–11570 is hereby amended by adding thereto authorization to sell natural gas from the additional acreage which is the subject of the instant application in Docket No. CI62–179.

(F) The docket designation, Docket No. CI62–179, is hereby cancelled.

(G) The related rate schedules listed below are accepted for filing to be effective on the date of initial delivery. Such acceptance for filing shall not be construed as constituting approval by this Commission of any service, rate, charge, classification, nor any rule, regulation or practice affecting such service or rate; nor shall this order be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Applicants involved. Further, in the event that any document comprising the listed rate schedules was executed on or after April 3, 1961, and contains provisions, either therein or by adoption of the terms and provisions of other agreements, for a change in rate other than those permitted by Section 154.93 of the Commission's Regulations under the Natural Gas Act, such rate change provisions shall be inoperative and of no effect at law and any tendered rate change under such provisions will be rejected.

Docket No.	Rate Schedule Designation	Description and Date of Document
CI62–117	Davisson A. Benson, Jr. FPC Gas Rate Schedule No 2	Contract, 6–30–61
CI62–170	George L. Yaste d.b.a. Oil States Sales Co. FPC Gas Rate Schedule No. 3.	Contract, 4–10–61

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

PUGET SOUND POWER & LIGHT COMPANY AND PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY, WASHINGTON, PROJECT NO. 943; PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY, WASHINGTON, PROJECT NO. 2114

ORDER ON QUESTION CERTIFIED BY PRESIDING EXAMINER

(Issued May 29, 1962)

The Commission's order of September 5, 1961 setting hearing in the above-entitled proceeding specified two issues upon which evidence was to be pre-

sented. On May 10, 1962, the Presiding Examiner, on his own motion, certified a question to the Commission concerning that order. The Examiner asks whether he should: (1) issue an initial decision, including findings, conclusions, and order on all of the material issues of fact and law; or (2) limit his decision to findings on the two specific factual issues referred to in the order of September 5, 1961.

Paragraph (D) of the September 5, 1961 order states that the Commission's Rules of Practice and procedure shall apply in this proceeding except to the extent that they are modified or supplemented therein. Section 1.30(a) of the Rules of Practice and Procedure requires an initial decision by the Presiding Examiner unless an exception is made pursuant to subsections (b) or (c) of Section 1.30. There has been no request for an exception in this proceeding. The Commission's order of September 5, 1961 did not modify the requirements of Section 1.30(a) of the Rules of Practice and Procedure. Therefore, the Presiding Examiner should proceed to make an initial decision, including such findings, conclusions, and order as he deems appropriate for disposition of the questions presented.

The Commission orders:

This matter is returned to the Presiding Examiner for an initial decision.

CERTIFICATION OF QUESTION AS TO SCOPE OF PRESIDING EXAMINER'S INITIAL DECISION

TO THE COMMISSION:

Pursuant to Section 1.27(b)(8) of the Commission's Rules of Practice and Procedure, and in order to avoid the problems and delays that may result from an erroneous interpretation of the language of limitation in the Commission's Order, the Presiding Examiner certifies the question set out below to the Commission for its consideration and disposition.

The Commission's Order Fixing Hearing in the above-entitled proceeding issued September 5, 1961, limited the presentation of evidence to the following issues:

(1) What specific adverse effects, if any, will operation of the Wanapum Development have on the three fishways at Rock Island Dam?

(2) What specific construction would be necessary to modify the three existing fishways at Rock Island Dam to correct any adverse effects that will be caused by operation of the Wanapum Development?

The hearing concluded January 29, 1962, and all briefs have now been submitted.

The Staff brief contains a complete set of proposed findings, conclusions, and suggested order on all the material issues of fact and law before the Commission, including the question of the Commission's jurisdiction and the liability of the parties for any modification that may be required. The briefs of the parties, however, including the interveners, limit their proposed findings to the two factual issues set forth in the Commission's Order and do not include findings and conclusions or a proposed Commission Order on the legal issues of jurisdiction and liability.

The Presiding Examiner can, of course, issue an intial decision, as suggested by the Staff, including findings, conclusions, and order on all of the material issues of fact and law. On the other hand, the Presiding Examiner may limit his decision to findings on the two specific factual issues referred to in the Commission's Order setting the hearing.

The ambiguity in the language of the Order, together with the different interpretations of its scope implicit in the briefs, raises a question as to the appropriate scope of the initial decision herein.

Accordingly, further guidance from the Commission is sought.

Respectfully submitted this 10th day of May 1962.

WILLIAM C. LEVY,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NOS. G-9174, G-9387, G-11039, G-11081, G-13427, G-13431, G-15074, G-15452, G-15508, G-16485, G-16650

ORDER ACCEPTING OFFER OF SETTLEMENT, TERMINATING PROCEEDINGS AND PROVIDING FOR REFUNDS

(Issued May 29, 1962)*

On April 19, 1962, Tennessee Gas Transmission Company (Tennessee) [1] submitted an Offer of Settlement in the above-designated proceedings pursuant to Section 1.18(e) of the Commission's Rules of Practice and Procedure.

The above dockets relate to consolidated rate proceedings arising from proposed increased rates tendered for filing by Tennessee pursuant to Section 4 of the Natural Gas Act. The increased rates were suspended and subsequently placed in effect subject to refund. Hearings concerning the lawfulness of such proposed increased rates were begun on February 9, 1960, and after recesses, were concluded on June 7, 1960.

Three parties had intervened in one or more of the respective proceedings namely, Mississippi River Fuel Corp., the Public Service Commission of the State of New York, and United Fuel Gas Company. The first two of said intervenors did not appear at the hearing. United Fuel Gas Company entered an appearance but its participation was limited to a statement of position agreeing to Tennessee's increased rates.

The presiding examiner rendered a decision in January, 1962, denying all of Tennessee's proposed increased rates except that an increased rate of 17.55¢ per Mcf was held to be proper under its FPC Gas Rate Schedule No. 33-A. Extensive exceptions to the examiner's decision were filed by Tennessee.

The rates that Tennessee proposes in its Offer of Settlement as the effective rates for the rate schedules in the above respective dockets are as follows:

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[1] Successor in interest to Middle States Petroleum Corporation which in turn was successor in interest to Midstates Oil Corporation.

*Amended by order issued August 27, 1962, 28 FPC 336.

Suspension Docket No.	Rt. sch. desig.	Purchaser	Location	Rates [1]		Prop. eff. date
				In effect subj. to ref.	Settlement	
G-11081	----------	Texas Eastern Transmission Company.	Franklin & Madison Parish, La.	[2] 14.6405	[2] 14.6405	4- 5-57
G-13427	F-4A			[2] 14.8456	[2] 14.8456	4- 4-48
G-16650				[3] 15.8007	[3] 15.75	4-13-59
G-11081	----------	Texas Eastern Transmission Company	Caddo & De Soto Parish, La.	[2] 14.605	[2] 14.6405	4- 5-57
G-13427	F-40A			[2] 14.8456	[2] 14.8456	4- 4-58
G-16650				15.8007	[3] 15.75	4-13-59
G-16650	F-50A	Texas Eastern Transmission Company.	Caddo & De Soto Parish, La.	[3] 15.8007	[3] 15.75	4-13-59
G-15508	F-51A	Texas Eastern Transmission Company.	Harrison County, Tex.	14.4	14.0	9- 2-58
G-16650				14.6		
G-9174	F-7A	Mississippi River Fuel Corp.	Harrison & Marion Counties, Tex.	13.73085	13.73085	1- 9-56
G-15452				14.0	14.0	5-12-61
G-9174	F-11A	Mississippi River Fuel Corp.	Harrison County, Tex.	13.73085	13.73085	1- 5-56
G-15074				14.0	14.0	11- 6-58
G-9387	F-33A	United Fuel Gas Company.	Acadia Parish, La.	[2] 17.4	[2] 17.4	4- 5-56
G-11039				[2] 17.8	[2] 17.75	4- 5-57
G-13431				[3] 18.2		
G-16485				[3] 19.35		

[1] At a pressure base of 15.025 PSIA in Louisiana and 14.65 PSIA in Texas.
[2] Includes a 1.0¢ per Mcf Louisiana severance tax reimbursement.
[3] Includes a 1.75¢ per Mcf Louisiana severance tax reimbursement.

All of the proposed settlement rates for the sale of gas in East Texas and North Louisiana area are at or below the area ceiling rates as set forth in the Commission's Statement of General Policy No. 61–1, as amended. The rate proposed by Tennessee for the sale of gas to United Fuel Gas Company in South Louisiana is at the base initial contract rate plus applicable tax reimbursement, which is below the initial rate for the area as contained in such Policy Statement as amended.

Tennessee is to refund to its purchasers the monies collected, under its corporate agreements and undertakings, at the rates which are in excess of the above stated settlement rates. Additionally, Tennessee states that the settlement rates set forth hereinabove are acceptable to the pipeline purchasers who purchase gas from Tennessee pursuant to the designated rate schedules. No party has objected to the offer of settlement.

In view of the foregoing and without passing on the validity of the exceptions to the decision of the presiding examiner, it appears that the public interest will best be served by accepting Tennessee's Offer of Settlement as hereinafter provided, the decision of the Presiding Examiner thereby becoming moot.

The Commission finds:

(1) The proposed settlement of these consolidated proceedings on the basis described herein, as more fully set forth in the Offer of Settlement filed by Tennessee on April 19, 1962, is in the public interest and appropriate to carry out the provisions of the Natural Gas Act and should be approved and made effective as hereinafter ordered.

(2) Good cause exists for disallowing all increased rates in excess of the settlement rates and for terminating the consolidated proceedings in the above-captioned dockets.

The Commission orders:

(A) The Offer of Settlement filed by Tennessee on April 19, 1962, is hereby approved in accordance with the provisions of this order.

(B) Tennessee shall execute with the purchasers under the rate schedules designated herein amendments to the gas purchase contracts to implement the provisions of the Offer of Settlement and file with the Commission within 45 days of the issuance of this order such amendments as supplements to the contracts involved.

(C) Within 45 days from the date of issuance of this order, Tennessee shall refund to its purchasers the difference between the amounts collected from such purchasers and the settlement rates in the Offer of Settlement, together with simple interest at the rate of 6 percent per annum from the respective dates of receipt of said excess amounts by Tennessee to the dates of refund. Tennessee shall bear all costs incidental to the making of such refunds.

(D) Within 45 days from the date of issuance of this order, Tennessee shall report to the Commission in writing and under oath the details of its calculations resulting in refunds ordered pursuant to paragraph (C) above, together with copies of releases from its purchasers with respect to such refunds.

(E) All increased rates in the above dockets in excess of the settlement rates are disallowed and upon full compliance by Tennessee with all terms and provisions of this order the consolidated proceedings in such dockets will be terminated.

(F) The acceptance of this Offer of Settlement is without prejudice to any findings or determinations that may be made in any proceedings which are presently being heard, or in any other proceedings now pending, or hereinafter instituted by or against Tennessee.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

LAKE SHORE PIPE LINE CO., DOCKET NO. RP60-1

ORDER APPROVING OFFER OF SETTLEMENT

(Issued May 31, 1962)

On February 4, 1960, Lake Shore Pipe Line Co. (Lake Shore) tendered for filing Third Revised Sheet No. 8-H, Sixth Revised Sheet No. 8-B, Ninth Revised Sheet Nos. 4 and 6 and Eleventh Revised Sheet Nos. 5 and 7 to its FPC Gas Tariff, Original Volume No. 1, proposing an increase in rates in excess of $830,000 per year to its affiliate, and only wholesale customer, East Ohio Gas Company (East Ohio).

Subsequent to a suspension order issued March 3, 1960, in this proceeding, the Commission permitted said revised sheets to become effective as of April 5, 1960, subject to the terms and conditions set out in the order issued herein on June 1, 1960. By order issued June 24, 1960, the City of Cleveland, Ohio, was permitted to intervene.

Following several pre-hearing conferences, Lake Shore placed an offer of settlement in the record.[1] The offer includes the filing of a proposed FPC Gas Tariff, First Revised Volume No. 1, to supersede as of January 1, 1962, Lake Shore's existing Tariff, under which Lake Shore has been collecting the increased rates involved in this proceeding.

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[1] Transcript pp. 11-23. On May 15, 1962 Lake Shore filed and served on the parties to this proceeding a corrected Exhibit No. 2 to the settlement which makes no changes to the proposed settlement, but merely corrects an inadvertent error in the computation reflected in original Exhibit No. 2.

The aforementioned First Revised Volume No. 1 is composed of a cost-of-service form of rate schedule and appropriate General Terms and Conditions under which Lake Shore proposes to sell and deliver gas to East Ohio in lieu of the currently effective contract-demand form of rate herein under review. Said cost-of-service rate schedule provides that East Ohio shall have a continuing option to take any quantities of natural gas resulting from new production developed by Lake Shore in Ohio and in event such option is not exercised, Lake Shore shall credit to its total cost of service all revenues received from the sale of natural gas or oil realized from such production.

The proposed settlement also provides that Lake Shore makes refunds in the amount of $146,508 for the period from April 5, 1960 through December 31, 1961, plus interest at 7% per annum from the date of receipt of the excess amounts by Lake Shore until refunded. For the period from January 1, 1962 to the date of the issuance of this order, Lake Shore is required by the proposal to re-compute its charges to East Ohio in accordance with the aforementioned cost-of-service rate schedule. Any revenues collected under the filed rate in excess of such re-computed statements are to be refunded, with interest as hereinbefore set out and as required by order issued June 1, 1960.

Lake Shore, on the record, also advised the Commission that the managements "of Lake Shore and its affiliates are presently engaged in studying . . . plans under which the facilities of Lake Shore would be absorbed into other companies in the Consolidated Natural Gas System."

The aforementioned proposed settlement is based (1) upon costs-of-service, which our staff has found to be appropriate, and (2) upon a corporate realignment which contemplates a limited life for the Respondent in this proceeding. No party to the proceeding has objected to the proposed settlement. We are of the view that the settlement as proposed is in the public interest.

The Commission finds:

(1) The increased rates and charges contained in Lake Shore's Third Revised Sheet No. 8–H, Sixth Revised Sheet No. 8–B, Ninth Revised Sheet Nos. 4 and 6, and Eleventh Revised Sheet Nos. 5 and 7 to its FPC Gas Tariff, Original Volume No. 1, have not been shown to be just and reasonable or otherwise lawful under the provisions of the Natural Gas Act, and should be disallowed as hereinafter provided and ordered.

(2) The refund and rate proposal embodied in the settlement proposal appear to be in the public interest and therefore should be approved as hereinafter provided.

(3) Good cause exists for waiving the 30-day notice requirement provided in Section 154.22 of the Commission's Regulations under the Natural Gas Act so that the cost-of-service form of rate contained in the proposed tariff may become effective as of January 1, 1962, as hereinafter ordered.

The Commission orders:

(A) The increased rates and charges contained in Lake Shore's tariff sheets referred to in paragraph (1) above are disallowed and denied.

(B) The refunds and the cost-of-service form of rate embodied in the settlement proposal, hereinbefore noted, are approved and made effective, subject to the terms and conditions hereinafter ordered.

(C) Within 30 days from the date of this order, Lake Shore shall file, subject to acceptance by the Commission, its revised tariff containing the cost-of-service form of rate and the general terms and conditions applicable thereto, all as set out in the hearing record of this proceeding.

(D) The 30-day notice provisions set out in Section 154.22 of our Regulations is hereby waived and the revised tariff required by paragraph (C) is hereby

permitted to become effective as of January 1, 1962, subject to the terms and conditions of this order and of the settlement proposal as set out in the record of this proceeding.

(E) Within 45 days from the date of this order, Lake Shore shall refund to East Ohio the principal amount of $146,508, for the period from April 5, 1960, through December 31, 1961, plus interest at 7% per annum, from the date of payment of such excess until date of refund.

(F) In addition to the refunds required by paragraph (E), within 45 days from the date of this order, Lake Shore shall re-compute its billing statements to East Ohio for sales from and after January 1, 1962, in accordance with the aforementioned cost-of-service form of rate and shall refund the difference between the revenues actually collected and those which would have been collected pursuant to the re-computed billing statements, plus interest at 7% per annum.

(G) Within 15 days after refunding the excess revenues required by paragraphs (E) and (F), Lake Shore shall report to the Commission, in writing and under oath, the amount of the refund made, showing separately the amount of principal and interest so paid, and shall serve a copy of such report upon East Ohio. Concurrently, therewith, Lake Shore shall file with the Commission a release from East Ohio which shows the receipt of the aforementioned principal and interest.

(H) Upon full compliance by Lake Shore of all the terms and conditions of this order, and acceptance by the Commission of the rate filing required by paragraph (C) the proceeding shall be considered terminated.

(I) This order is without prejudice to any findings or orders which have been or may hereafter be made by the Commission and is without prejudice to any claims or contentions which may be made by the Commission, the Commission Staff, Lake Shore, or any other party affected by this order, in any proceeding now pending or hereafter instituted by or against Lake Shore or any other company, person or party affected by this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

THE MONTANA POWER COMPANY, PROJECT NO. 2188

ORDER APPROVING SUPPLEMENTAL EXHIBIT L DRAWING

(Issued May 31, 1962)

On April 10, 1962, The Montana Power Company, licensee for major Project No. 2188, filed for Commission approval a supplemental Exhibit L drawing for the spillway of the constructed Hauser Lake development of the project.

Our approval of the supplemental drawing would authorize the licensee to install 20 spillway gates to replace existing flashboards in 5 of the 24 bays (4 gates in each bay) in the spillway of the Hauser Lake dam. Each gate will be 4 feet 7 inches wide by 6 feet 10 inches high. Flashboards will be retained in the remaining 19 bays.

The licensee states that installation of the gates will improve control of reservoir levels and reduce the amount of water wasted each year. It will no longer be necessary to drawdown the reservoir to allow removal of flashboards preceding the spring runoff, except during years of high flow.

While the total spillway capacity will be reduced, our studies show that such reduction will not be sufficient to endanger project structures during spillway design flood flows, and we consider the modified spillway as adequate.

The Commission finds:

Exhibit L, Sheet 4A (FPC No. 2188–89) entitled "Hauser Lake Hydro Electric Development, Spillway Gate Installation", supplementing Exhibit L, Sheet 4 (FPC No. 2188–72), now part of the license for Project No. 2188, conforms to the Commission's rules and regulations and should be approved as part of the license for the project.

The Commission orders:

The supplemental Exhibit L drawing described in the above finding is approved as part of the license for Project No. 2188.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

SOCONY MOBIL OIL COMPANY, INC., DOCKET NO. G–13780

ORDER AMENDING ORDER GRANTING MOTION FOR STAY

(Issued May 31, 1962)

On March 30, 1962, this Commission issued an order in this proceeding granting in part a motion for stay filed by the Applicant herein on March 12, 1962. By said order we stayed ordering paragraphs (A), (C) and (D) of the order of February 9, 1962, herein, for a period of 60 days following the Commission's final action upon the application for rehearing filed herein.

On May 15, 1962, the Applicant filed a motion requesting the Commission to amend its order of March 30, 1962, so as to extend the stay of said ordering paragraphs to (a) "30 days after conclusion of judicial review of the Commission's Order * * *, issued February 9, 1962", or (b) "90 days after final action by the Commission upon the Application for Rehearing * * * filed in these proceedings."

We do not believe that the public interest will be adversely affected by deferring payment of the refunds, with interest, which we have found to be proper in the order of February 9, 1962, for a period of 30 days after conclusion of judicial review of the said order, and by extending to Applicant a stay of 90 days from the date of our final action in these proceedings, i.e., the date of the issuance of our order denying rehearing which was April 6, 1962, to place into effect the rate set forth in ordering paragraph (C) of the said order of February 9, 1962, aforementioned, as hereafter provided.

The Commission finds:

Good cause exists for granting, in part, the motion filed by Applicant on May 15, 1962, for an amendment to the order issued herein on March 30, 1962, so as to stay the actions required by ordering paragraphs (A) and (D) for a period of 30 days after conclusion of judicial review of the order issued February 9, 1962, aforementioned, and to stay the effect of the conditions set forth in ordering paragraph (C) of said order until 90 days from the date of our order of April 6, 1962, aforementioned, subject to the reporting condition hereinafter imposed by the *proviso* to ordering paragraph (B) below.

The Commission orders:

(A) The conditions and requirements set forth in ordering paragraph (C) of the order issued February 9, 1962, to and as a part of the permanent certificate of public convenience and necessity issued thereby, are hereby stayed until 90 days from the date of the order denying rehearing issued herein on April 6, 1962.

(B) The completion of the acts and compliance with the requirements set

forth in ordering paragraphs (A) and (D) of the said order, are hereby stayed for a period of 30 days after conclusion of judicial review of said order issued February 9, 1962, *provided, however*, that Applicant shall file with the Commission, no later than June 15, 1962, an officially certified statement computing and reporting the principal amount of the refunds which have been ordered by ordering paragraph (A) of the order issued February 9, 1962, for all volumes delivered in the period from initial delivery through March 31, 1962.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

UNITED STATES DEPARTMENT OF THE INTERIOR, SOUTHWESTERN POWER ADMINISTRATION, DOCKET NO. E-6582

ORDER CONFIRMING AND APPROVING RATES AND CHARGES

(Issued May 31, 1962)

The Assistant Secretary of the Interior, on behalf of the Southwestern Power Administration (SWPA), pursuant to the Flood Control Act of 1944 (58 Stat. 887), on April 30, 1962, filed a request for confirmation and approval of its presently effective rates and charges for the sale of electric power generated at the Whitney Project to Brazos Electric Power Cooperative, Inc. (Cooperative) for the five-year period beginning June 1, 1962. Those rates and charges are contained in an agreement dated November 17, 1953, between SWPA and the Cooperative, and represent a continuation for an additional five-year period of rates and charges which were approved by the Commission's order issued December 23, 1954, in the above-entitled docket (13 FPC 1632) for an initial five-year period commencing December 23, 1954, and subsequently were extended for a period ending May 31, 1962, by the Commission's order issued February 5, 1960 (23 FPC 310).

The afore-mentioned agreement, which extends for 35 years from the date of the commencement of service, provides that the rates and charges contained therein shall remain in force for a period of five years from the date of initial approval by the Commission, at which time and at the end of each succeeding five-year period thereafter they shall be reviewed and redetermined.

The agreement provides *inter alia* for the delivery to Cooperative of the entire output of the Whitney Project, which includes 30,000,000 kwh per year of primary energy and an average of 51,760,000 kwh per year of secondary energy. Cooperative will pay an annual charge of $441,000 in equal monthly payments of $36,750, and will receive the following credits to that charge: (a) 12.49 mills for each kwh of primary energy which SWPA is unable to deliver because of lack of water; (b) 11.21 mills for each kwh of primary energy which SWPA is unable to deliver for any reason except scheduled outages or lack of water; and (c) 1.28 mills for each kwh of energy which could have been generated by the use of water spilled through no fault of Cooperative.

Under an agreement dated November 17, 1953, with Texas Power & Light Company (Texas Power), Cooperative resells the power and energy received from the Whitney Project to that Company, and in turn Texas Power makes available a maximum of 28,000 kw of firm power and associated energy to Cooperative.

A current repayment study submitted by SWPA in support of the continued application of the present rates and charges indicates that all costs associated

with the Whitney Project power operations will be repaid within a 53-year period beginning with the fiscal year 1956, the first full year of commercial operation under the afore-mentioned long-term contract with Cooperative.

Notice of the proposed rates and charges was sent to interested State officials and published in the Federal Register on May 11, 1962 (27 F.R. 4538), stating that any person desiring to make comments or suggestions with respect thereto should submit the same on or before May 21, 1962. No comments or suggestions have been received.

The Commission finds:

The continued application of the rates and charges contained in the agreement dated November 17, 1953, between SWPA and Cooperative for the sale of electric power produced at the Whitney Project to Cooperative for a period of five years beginning June 1, 1962, will not be inconsistent with the purposes of the Flood Control Act of 1944.

The Commission orders:

The proposed rates and charges contained in the agreement dated November 17, 1953, between SWPA and Cooperative for the sale of electric power produced at the Whitney Project, and referred to above, hereby are confirmed and approved for a period of five years beginning June 1, 1962.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

ALABAMA-TENNESSEE NATURAL GAS COMPANY, DOCKET NOS. G-5471, G-11982, G-17218 AND G-19984

ORDER SETTING ORAL ARGUMENT, PROVIDING FOR PARTICIPATION OF AMICI CURIAE AND FOR FILING OF BRIEFS

(Issued June 1, 1962)*

Among other matters, there is in issue in these rate proceedings the question of the treatment of liberalized depreciation deductions in the computation of income taxes to be allowed Alabama-Tennessee Natural Gas Company for rate-making purposes. The existing precedent as set out in Opinion No. 326, *El Paso Natural Gas Company*, Docket No. G-4769, 22 FPC 260, 266-267, is to the effect that a natural-gas company will be permitted to include in its cost of service income taxes on the basis of straight line depreciation, while paying such taxes on the basis of liberalized depreciation. In Opinion No. 342, *Northern Natural Gas Company, et al.*, Docket Nos. G-19040, etc., 25 FPC 431, it is concluded that the aforementioned use of liberalized depreciation should be taken into consideration in fixing a rate of return for the pipeline company by including the amounts in the deferred income tax account resulting therefrom as part of the company's capitalization and providing for an allowance of 1.5 percent return thereon.

This Commission has indicated in a number of recent orders that it proposes to reexamine this matter.[1]

It is appropriate, in the circumstances, that we provide for oral argument in these proceedings on the question of the treatment for rate-making purposes to be accorded the use of liberalized depreciation deductions by a pipeline company in the computation of its income taxes and of accumulated deferred taxes in the determination of rate of return.

Specifically, we desire to hear arguments directed toward the several possibilities for handling this matter, namely, use of the present procedure with rates of return at 0, 1.5, or such higher rate as may be deemed to be in the public interest, or, alternatively, use of the so-called "flow-through" principle under which the reduction in taxes through the use of liberalized depreciation instead of straight-line depreciation, would be reflected in income taxes included in the pipeline's cost of service. We believe we would be aided in our consideration of this problem by the participation as *amici* either in the oral argument, or by the filing of written briefs, by any person, company, association or governmental authorities having an interest in the problem. In order, however, to keep the proceeding within manageable bounds we shall direct all such persons to state the position which they wish to advocate in their requests for participation, and we reserve the right to specify by subsequent order that persons taking the same position file joint briefs or designate a single member of their group to present the oral argument.

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*Reconsideration denied by order issued July 30, 1962, 28 FPC 240.

[1] See orders issued February 13, 1962, in *Idaho Power Company*, Project Nos. 18 and 503, 27 FPC 349; *Minnesota Power & Light Company*, Project Nos. 346 and 419, 27 FPC 354; *Southern California Edison Company*, Project Nos. 67, 120 and 382, 27 FPC 360; order issued February 28, 1962, *In the Matter of New England Power Company*, 27 FPC 404; and order issued April 2, 1962, in *California Electric Power Company*, Project No. 344, *et al*, 27 FPC 658.

The Commission orders:

(A) Oral argument before the Commission on the issue of the treatment to be accorded for rate-making purposes of liberalized depreciation deductions under Section 167 of the Internal Revenue Code used by a pipeline company in the computation of its income taxes and of accumulated deferred taxes in the determination of the rate of return and the alternatives specifically set forth above, shall be held on July 10, 1962, at 10:00 a.m. (EDT) in a Hearing Room of the Federal Power Commission, 441 G Street, NW., Washington, D.C.

(B) Any person, company, association, or governmental authority having an interest in the problem shall file on or before June 14, 1962, a request to participate either as *amicus* in the oral argument or to file written briefs and shall, in that request, specify the position it proposes to advocate in this matter.

(C) Any parties to these proceedings who intend to participate in the oral argument and any *amici* granted permission to present oral argument shall notify the Secretary of the Commission on or before June 29, 1962, of the time requested for presentation of such argument.

(D) Any party to these proceedings or any *amici* granted permission by the Commission to do so may file a written brief on the issue herein set for oral argument on or before July 3, 1962.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

THE ATLANTIC REFINING COMPANY, DOCKET NOS. G–15678 AND G–15719

ORDER GRANTING EXTENSION OF TIME

(Issued June 1, 1962)

By its order issued March 5, 1962, in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, 27 FPC 441, the Commission disposed of more than 400 proceedings, including those above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. With respect to the instant dockets, ordering paragraph (A) of the March 5 order directed The Atlantic Refining Company (Atlantic) to refund tax-reimbursement amounts collected from its direct customer Texas Gas Transmission Corporation (Texas Gas). Ordering paragraph (C) of the March 5 order directed that within 90 days from the date of issuance thereof, Atlantic report to the Commission the details of its refund calculations and submit copies of releases from Texas Gas as to the required refunds. By order issued April 26, 1962 in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, 27 FPC 847, the Commission denied applications for rehearing of the March 5 order in the above, as well as other, dockets. On May 22, 1962 Atlantic filed a motion seeking to stay the effectiveness of the March 5 order, insofar as applicable to the above dockets, until 30 days after conclusion of judicial review of said order in those dockets. The motion recites that Atlantic intends to seek judicial review of the March 5 order and that failure of the Commission to grant the stay pending such review would cause it irreparable injury.

For reasons stated in our order of April 13, 1962 granting Pan American Petroleum Corporation an extension of time for compliance,[1] we are disposed to

[1] Pan American Petroleum Corporation, Docket No. G–15641; Pan American Petroleum Corporation (Operator), *et al.*, Docket Nos. G–15650 and G–15780, 27 FPC 686.

extend the time within which Atlantic must comply with ordering paragraphs (A) and (C) of the Commission's March 5 order, for a period ending 30 days after conclusion of judicial review of that order in the instant dockets.[2] The extension is conditional, however, upon the payment by Atlantic to Texas Gas of interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the order of March 5.

The Commission finds:

(1) There is good cause for extending the time within which Atlantic must comply with the requirements of ordering paragraphs (A) and (C) of our order of March 5, 1962, for a period ending 30 days after conclusion of judicial review of that order in the instant dockets.

(2) It is just and reasonable and in the public interest that Atlantic be required to pay Texas Gas interest, at a rate of 7% upon the amounts to be refunded, for the period commencing on the 91st day after issuance of the March 5 order.

The Commission orders:

(A) The time within which Atlantic must comply with ordering paragraphs (A) and (C) of the Commission's order of March 5, 1962 is extended for a period ending 30 days after the conclusion of judicial review of the Commission's order.

(B) Atlantic shall pay Texas Gas interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the March 5, 1962 order.

(C) The time within which Texas Gas must comply with ordering paragraphs (B) and (D) of the March 5, 1962 order, insofar as applicable to the instant dockets, is extended for a period ending 60 days after conclusion of judicial review of that order in said dockets.

(D) If Atlantic shall not have filed petitions for review of the March 5 order in the instant dockets within the 60 day period prescribed by statute, the extension of time herein granted shall be deemed inoperative and of no effect.

COLORADO INTERSTATE GAS COMPANY, DOCKET NO. G–20521

ORDER ADOPTING PRESIDING EXAMINER'S DECISION ON RATE FORM

(Issued June 1, 1962)*

Syllabus

1. Interpreting Tariff provision, Commission *holds* that no applicant is deemed to have waived any rights it may have under Section 7(a) of the Natural Gas Act by reason of such provision; moreover it is not construed as an encroachment on Commission's power to act under Section 7(a) of the act. P. 1066.
2. Natural Gas Act does not require company to generally supply additional gas to customers at a loss, nor does it give Commission power to compel the pipeline to make a blanket stipulation in its tariffs to the effect that it will supply additional gas. P. 1072.

[2] It should be understood that the 30th day after judicial review in the instant dockets is the date upon which Atlantic must comply with the March 5 order; it is *not* the date upon which the 90 day period referred to in ordering paragraph (C) commences to run.

* Initial Decision appears on Page 1066.

3. Commission *approves* Colorado Interstate's use of contract demand form of gas tariff and *terminates* proceeding initiated under Section 4(e) of the Natural Gas Act. P. 1066; 1077.

Duke W. Dunbar and *Jacob Goldberg* for Colorado Public Utilities Commission.

E. A. Stansfield for Public Service Company of Colorado, Colorado-Wyoming Gas Company, and The Pueblo Gas & Fuel Company.

Ishier Jacobson, Reuben Goldberg, and *George Spiegel* for Citizens Utilities Company.

E. A. Stansfield for Greeley Gas Company.

Raymond D. Nixon and *Louis Johnson* for Colorado Springs Department of Public Utilities.

Donald E. Kelly, Charles S. Rhyne, Hersel H. E. Plaine, and *Thomas P. Brown, III* for City and County of Denver.

C. H. Ross, Charles C. McDugald, Lowell E. Sachnoff, and *William W. Brackett* for Natural Gas Pipeline Company of America.

John E. Miles, Hilton A. Dickson, Jr., and *Fredeirck G. Von Huben* for New Mexico Public Service Commission.

K. W. Kissick and *O. F. Adams* for City of Trinidad, Colorado.

James L. White, John Fleming Kelly, and *W. Russell Gorman* for Colorado Interstate Gas Company.

Edmund M. Sciullo for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

The Presiding Examiner's decision upon Colorado Interstate Gas Company's proposed revision of the rate form of its tariff to a "standard form of contract demand" was issued and served upon all the parties on May 2, 1962. No exceptions thereto have been filed by any party to the proceeding.

However, a number of parties have raised a question of interpretation with respect to Section 17(d)(2) of the General Terms and Conditions in the proposed tariff which provides, in part:

> Seller shall not be obligated to supply the requested additional gas if Seller determines in its judgment that it cannot do so economically.

Notwithstanding the foregoing provision of the tariff, no applicant for gas supply or additional gas supply is deemed to have waived any rights it may have under Section 7(a) of the Natural Gas Act. Moreover, that provision is in no manner construed as an encroachment on this Commission's power to act upon any application filed under that section.

With the foregoing interpretation, the examiner's decision hereby is adopted as the final decision and order in this proceeding.

DECISION

ACCEPTING SUBSTITUTE GAS TARIFF AND TERMINATING PROCEEDING

(Issued May 2, 1962)

WESTON, *Presiding Examiner:* On December 31, 1959, the Commission approved a settlement of Colorado Interstate's rate-increase filings in Docket No. G–13541. (See 22 FPC 1180.) The settlement, to which all parties and customers agreed, contemplated the restatement of Colorado Interstate's existing G–1 and P–1 tariffs to the "standard form of contract demand" gas tariff.

Such restatement had been proposed in a new tariff filing tendered September 28, 1959, and revised on December 21, 1959, to reflect the "settlement rates restated on an equivalent basis to the contract demand form." (22 FPC at 1182.)

The settlement was intended to, and did, resolve all questions as to the level of rates to be charged by Colorado Interstate to its customers beginning with the calendar year 1959. Beginning with January 1, 1960, however, the contemplated restatement of the G–1 and P–1 tariffs in the contract demand form necessarily also contemplated and required a recomputation of demand charges as set out in the superseded tariffs. The settlement specified that instead of $1.50 per Mcf demand charge in the former G–1 rate schedule, the "demand charge of the G–1 rate shall be $1.36 to reflect the new contract demand form of tariff proposed" by the September 28, 1959, filing mentioned above; similarly, the former P–1 charge of $1.04 would be 94 cents to reflect such change in rate form. (21 FPC at 1186.) And the parties to the settlement reserved "all rights as to all matters with respect to said filing of September 28, 1959, except as to the level of rates contained therein as herein provided." (*id.*)

By separate order also issued on December 31, 1951, 22 FPC 1180, the Commission instituted the proceeding at bar by suspending the above-mentioned new tariff filing, on the basis of findings that the new tariff sheets "represent a filing relating only to rate form, not rate level," but that Colorado Interstate's customers "have indicated some objection to the change in rate form." On June 1, 1960, the new tariff became effective, subject to refund, and has since been applied to Colorado Interstate's customers. By order issued June 14, 1960, the Commission permitted the new tariff to become effective as of June 1, 1960, subject to refund of any excess charges collected thereunder. On August 16, 1960, the Commission set the proceeding down for hearing September 21, 1960, on a recital that—

> The proposed tariff revisions in principal part relate to a change in Colorado Interstate's G–1 and P–1 rate schedules to a "standard form of contract demand," and to inclusion of an SG rate schedule for small distribution companies. Because of the settlement of Docket No. G–13541, the proposed tariffs represent a filing relating only to rate form, not to rate level. [Footnote omitted.]

Many of the customer objections to the new form of tariff were settled in informal conferences prior to and during the course of the proceeding. There is no customer objection in principle to the contract demand form of rate, which is used by substantially all of the regulated pipelines serving, as does Colorado Interstate, several distribution company customers. The customers have since June 1, 1960, regularly nominated and settled their contract demand quantities for the heating seasons 1960-1961 and 1961-1962. In the meantime, since the closing of the record herein on October 26, 1960, we have had the benefit of two heating seasons of experience under the new form of tariff. We can now judge the results of such new tariff on the basis of the dollars-and-cents realities, without prejudice to any party to this record, or any consumers, on account of the delay. As will be seen, the results during the 1960-1961 heating season were inconclusive on the matter of customer claims that Colorado Interstate would profit unduly from the new tariff; the January 1962 peaks, however, furnished important factual data.[1]

The issues not resolved in informal conferences will be taken up in the separate sections which follow.

[1] In view of current emphasis on speeding the decisional process, it may be noted that the case at bar is one of many cases in which "policy delay," *i.e.*, deliberate delay in considering and deciding issues, is the proper course to be followed by the decision-maker.

Change in Billing Demand

Under Colorado Interstate's prior G–1 and P–1 tariffs, applicable until June 1, 1960, the customer's monthly Billing Demand was "the greater of the following—

"(1) The measured demand, or

"(2) 90% of the highest measured demand for the 11 months immediately preceding the current billing period."

This meant that each of the customers paid demand charges on the basis of the highest single day's actual take of Mcf's of gas during the given current month, but not less than 90 percent of the highest single day's actual take of Mcf's of gas during the preceding eleven months.

Under Colorado Interstate's new tariff, the customer's monthly Billing Demand is—

> * * * the highest day's delivery during the twelve months ended with the current billing month but not less than 90% of the Contract Demand nor more than the Contract Demand. (Exh. 4, original sheets 5 and 10.)

This means that each of the customers pay demand charges on the basis of the highest single day's actual "take" of Mcf's of gas during the twelve months ended with the current month, but not less than 90 percent of the amount nor more than the amount of the Contract Demand, which is the amount nominated each year by the customer and settled between the customer and Colorado Interstate, representing—

> * * * the maximum quantity of natural gas Seller is obligated to deliver on a firm basis to Buyer and Buyer is entitled to receive on a firm basis from Seller on any day. (Exh. 4, Original Sheet 22.)

The Public Service group of customers,[2] the Colorado PUC, and the Staff propose that the Billing Demand be the highest day's delivery during the current billing month, but not less than 90 percent of the Contract Demand nor more than the Contract Demand. This proposal thus eliminates, in the event of "takes" in the bracket between 90 percent and 100 percent of the Contract Demand, eleven months of Billing Demand charges in respect of such percentage of gas as is within the bracket.

Factors In Evaluating Contentions. A decision on the opposing contentions as to the proper computation of Billing Demand must accord with two basic principles applicable to this case:

First, we should note that the level of the rates which were arrived at in the settlement proceedings and agreed to by all of the parties, were determined on the basis of the test year costs and operations which were considered as representative of prospective costs and operations. Consequently, in this proceeding, any proposal which would result in a change in the level of rates, either up or down, would be in conflict with the terms of the settlement agreed to by the parties and approved by the Commission. Simply stated, the *status quo* must be preserved, and we must focus only on the question whether or not the new form of tariff accomplishes that goal.

Second, we should remember that demand charges are by definition associated primarily with the fixed costs of the pipeline system—costs of capital outlay and relatively constant operating expenses. Those costs are incurred to install and maintain Colorado Interstate's capacity to meet firm requirements, which

[2] Public Service Company of Colorado, a distribution company serving the Denver area, and its two wholly-owned subsidiaries Colorado-Wyoming Gas Company (a pipeline serving Northern Colorado and southeastern Wyoming), and Pueblo Gas and Fuel Company (a distributor in the Pueblo area). This group takes 83 percent of the gas involved in this tariff filing.

are substantially the firm requirements of Colorado Interstate's resale customers taking gas under the G–1 and P–1 rate schedules. Under the "Atlantic Seaboard Formula" (*Atlantic Seaboard Corp.*, 11 FPC 43, 54), 50% of the fixed costs are classified as demand cost, and such demand cost is allocated between jurisdictional and nonjurisdictional customers on a peak responsibility basis. In pipeline rate-making, demand charges are not quoted in terms of the peak take on an annual basis; rather, demand charges are quoted on a monthly basis in terms of the Billing Demand of the several customers as defined in their tariff. It is essential therefore that the Billing Demand provided in the tariff be computed pursuant to a method which fairly and equitably apportions among the various customers the demand cost related to the peak load imposed by those customers on the system. Moreover, the method of determining the Billing Demand should provide a reasonable and proper basis for the pipeline company to efficiently and economically build capacity additions. The new form of tariff assures more realistic market estimates than the old tariff, and provides "a means by which Colorado Interstate can recover a portion of its fixed costs incurred in supplying its customers with the delivery capacity they require on a more assured and stable basis. * * *" (Tr. 41.)

Factual Results of New Tariff. In order to have a basis for computing its possible refund obligations in the proceeding at bar, Colorado Interstate has, for each month since June 1, 1960, filed statements showing a comparison of actual billings to its customers under the contract demand form of tariff in effect since that date, with billings that would have been made under the old tariff. The statements as amended show the name of the customer, the applicable G–1[3] or P–1 Rate Schedule, the actual peak day "takes" during each month, the revenues at rates in effect immediately prior to June 1, 1960, the revenues actually collected, the difference in revenues (current month and total), and the applicable monthly contract demands. The statements are part of the public records of the Commission, subject to the safeguards applicable to documents of which official notice may be taken, and official notice is taken thereof.

We thus have available the actual and computed results of the new and old tariffs in operation for an adequate period of time to base a determination in the light of actual experience as to whether the Billing Demand provisions of the new tariff operate (a) to increase rate levels as established by the settlement agreement, (b) to otherwise disadvantage Colorado Interstate's customers in the respects advanced as potentials on brief. We can also compute the effect on Colorado Interstate of the application of the form of billing demand suggested by Staff and intervenors.

The monthly figures have been reviewed for the period from June 1, 1960, through January 31, 1962—a period which covers the 1960–61 and 1961–62 winter season.[4]

From all eleven of its resale customers using the G–1, SG–1, and P–1 Rate Schedules, Colorado Interstate realized from June 1, 1960, to January 31, 1962, the amount of $65,449 *less* revenues than would have been realized under the old tariff. In comparison to the $50,395,226 of total revenues involved (including commodity revenues) under the old tariff, the difference is .13 percent, or insignificant.[5] As to *each* of the eleven resale customers, the differences between

[3] Some of the customers, for small volumes, use an optional "SG–1" schedule about which there is no issue in this proceeding.

[4] The peak day for the 1961-62 winter season occurred on January 19, 1962, for Colorado-Wyoming Gas Co., and on January 10, 1962, for all other customers.

[5] To December 31, 1961, prior to the peak January month, the difference was only $15,996 less revenues, or .03 percent of revenues involved. Each month the total difference has been in the insignificant range.

the revenues collected under the new tariff and the revenues which would have been collected under the old tariff have also been insignificant. As of January 31, 1962, the range of difference was between Public Service Company of Colorado on the one hand, which had to that time incurred $107,207 *less* in charges than would have been payable under the old tariffs, and City of Colorado Springs on the other hand, which had incurred $53,720 *more* in charges on the same basis. Looking at the results of the new tariff on individual customers over the recent months since June 1, 1960,[6] there has, as in the case of the consolidated figures, been some variance in the plus or minus figures, but always in the relatively insignificant category when related to total charges.

Eliminating commodity charges and focussing exclusively on demand revenues from G–1 and P–1 customers, it is clear that overall in the period June 1, 1960, through January 1962, the effective new tariff is slightly more equivalent to the old tariff, in terms of revenues to Colorado Interstate, than the tariff charges proposed by intervenors and Staff would have been if in operation—and no individual customer was significantly prejudiced by the effective Billing Demand of the new tariff. Thus:

Colorado Interstate Gas Company, comparative summary of demand revenues: G–1 & P–1 customers, June 1, 1960–Jan. 31, 1962

Customer	Old tariff	New tariff	Proposed tariff
P.S. Co. of Colo.	$9,045,517	$8,938,310	$8,922,074
Pueblo G. & F. Co.	1,154,610	1,170,768	1,169,412
City of Colo. Springs	1,873,163	1,926,883	1,926,883
Greeley Gas Co.	134,631	130,996	123,721
Citizens Util. Co.	274,624	271,788	269,580
Colo-Wyo. Gas Co.	2,682,071	2,654,365	2,571,094
Kans-Colo. Utils. Inc.	1,227	1,094	1,094
SUMMARY			
Total revenues	$15,165,843	$15,094,204	$14,983,858
Over (under) old tariff	----------	[1](71,649)	[2](181,985)

[1] Amounts to ½ of 1% of revenues under old tariff.
[2] Amounts to 1.2% of revenues under old tariff.

It is noted that had the tariff proposed by the intervenors and Staff been in effect during the above 20-month period, the $181,895 difference in revenues to Colorado Interstate would also be insignificant. This is because the actual monthly peak day "takes" of gas by each of the G–1 and P–1 customers, up to December 1961, were less than 90 percent of the Contract Demand of each such customer, with three minor exceptions.[7] Thus conservative nominations of Contract Demand, favorable weather conditions, or a combination of these factors, up to the 1961–1962 heating season, made for inconclusive results in respect of the various contentions as to the proper basis for Billing Demand.

However, projecting results for 1962 on the basis of the January 1962 peaks produced highly significant results. Based on (1) current Contract Demand, (2) the peak day quantities actually used, and the (3) Billing Demand quantities computed under (a) the old tariff, (b) the new tariff, and (c) the intervenor-Staff proposed tariff, the estimated revenues would be as follows:

[6] *I.e.*, after a sufficient period of experience under the new tariff.

[7] In December 1960, Public Service Company of Colorado took 333,905 Mcf (90 percent of their Contract Demand = 332,820), Greeley Gas Co. took 4,671 Mcf (90 percent of their Contract Demand = 4,523), and Colorado-Wyoming Gas Co. took 131,735 Mcf (90 percent of their Contract Demand = 123,930).

Colorado Interstate Gas Company, 1962 estimated demand revenues: G–1 & P–1 customers

Customer	Old tariff	New tariff	Proposed tariff
P.S. Co. of Colo	$5,838,657	$5,827,937	$5,464,649
Pueblo G. & F. Co	790,068	788,615	725,454
City of Colo. Springs	1,349,384	1,338,240	1,215,568
Greeley Gas Co	93,939	85,272	77,463
Citizens Util. Co	178,114	171,456	155,739
Colo-Wyo. Gas Co	1,695,651	1,687,274	1,610,954
Kans-Colo. Utils. Inc	6,977	6,768	6,148
SUMMARY			
Total revenues	$9,952,790	$9,905,562	$9,255,975
Over (under) old tariff		[1](47,228)	[2](696,815)

[1] Amounts to ½ of 1% of revenues under old tariff.
[2] Amounts to 7% of revenues under old tariff.

The 1962 estimated demand revenues are significantly affected by the fact that the actual peak day "takes" of gas by G–1 and P–1 customers in January were substantially in excess of 90 percent of their contract demand quantities.[8] As heretofore noted ("Change in Billing Demand," *supra*), under the old tariff, such customers would have had a new "floor" on Billing Demand at 90 percent of the actual January 1962 peak day "takes" for the subsequent eleven months in 1962. Under the tariff proposed by intervenors and Staff, the "floor" would remain at 90 percent of Contract Demand for such months. Under the effective tariff now in issue, the "floor" for customers which in January took over 90 percent of Contract Demand is the actual amount of deliveries, but not more than Contract Demand.

Conclusion. The computation of Billing Demand as contained in Colorado Interstate's currently effective tariff is reasonable and proper, and Colorado Interstate's contingent obligation to make refunds on account of charges made and collected under such computation should be discharged. The computation of Billing Demand proposed by intervenors and Staff would result in a substantial reduction in Colorado Interstate's level of rates as agreed to in the settlement made in Docket No. G–13541, and should not be adopted.

Customer Requests For Additional Gas

Section 17 of the proposed General Terms and Conditions applicable to service by Colorado Interstate covers "Changes in Contract Demand." Paragraph 17.1(d) covers "Procedure If Additional Supplies or Facilities Required." Starting with the premise that Colorado Interstate (Seller) either (a) does not have additional supply available, or (b) must construct additional facilities, to serve a requested increase in Contract Demand, a procedure is set up "to attempt to make such additional supply available." Subparagraph 17.1(d)(2) provides—

> Seller shall not be obligated to supply the requested additional gas if Seller determines in its judgment that it cannot do so economically.

The Colorado PUC objects to this clause, as one implying Colorado Interstate's "unilateral right to refuse to supply increased nominated contract demands,"

[8] Colorado Springs, Greeley, Citizens, and Kansas-Colorado "takes" exceeded contract demands. Payments for unauthorized overruns were, however, excluded from computations because of the history of waivers of such payments by Colorado Interstate. Inclusion of such payments would add $10,514 to revenues under the New Tariff and the Proposed Tariff Summary above.

and ask for its elimination from the tariff. The City and County of Denver go further, and say that Colorado Interstate—

> should be obligated by a provision in its tariff to apply for a certificate of public convenience and necessity required for construction or extension of facilities under Section 7(c) of the Natural Gas Act if a customer requires more gas, is willing to pay a contract demand charge for a twenty year period, and this service cannot be granted without a certificate. * * * (Br. 1–2.)

1. The subject-matter field, "extension of facilities," is at least substantially occupied by the provisions of Section 7(a) of the Natural Gas Act, to the exclusion of provisions intended to govern such field and incorporated into the tariffs or contracts of private parties. Section 7(a) provides, in pertinent part and in effect, that the Commission may direct a pipeline to improve its facilities on a finding that such improvement will not place an "undue burden" on the pipeline, but that the Commission may not "compel the enlargement of transportation facilities" or new connections or sales which would impair the pipeline's "ability to render adequate service to its customers."

2. Colorado Interstate's customers have the rights and the Commission has the powers which are set forth in the Natural Gas Act, and no more. The Act does not require Colorado Interstate to generally supply additional gas to its customers at a loss, nor does the Act give the Commission power to compel the pipeline to make a blanket stipulation in its tariffs to the effect that it will supply additional gas to meet the needs of its customers. The Commission has no authority to exact in advance "some assurance that Colorado Interstate will supply the increased requirements of the Rocky Mountain Area." (Colorado PUC Br. 5.) Under the Natural Gas Act this matter is in the first instance left up to Colorado Interstate's management, which may or may not serve additional gas. or construct additional facilities as requested (on the basis of voluntarily filed Section 7(c) applications). In the event that such management does not meet its public service or reasonable obligations, the matter can be presented to the Commission under Section 7(a) of the Act or other provisions for relief.[9]

3. Subparagraph 17.1(d)(2) of the proposed tariff should be read in the light of the Natural Gas Act and the decided cases, including *Waynesboro Gas Co.*, 8 FPC 464; *Warwick Gas Corp.*, 11 FPC 667, 1496; *City of Red Bud* v. *Mississippi River Fuel Corp.*, 22 FPC 1081; and *Central West Utility Co.* v. *F.P.C.*, 247 F. 2d 306 (CA3).

Under the gloss of these cases, and of this present decision, it is unnecessary to add phraseology to tariff provision 17.1(d)(2) concerning non-waiver of customer rights granted by Section 7(a) of the Act (Denver Br. 10) or Colorado Interstate's obligation to act in good faith (Staff Br. 8). The provision is not deemed one which puts Colorado Interstate "in a position of 'picking and choosing' its customers * * * contrary to public law and regulation" (Staff Br. 7), but one which merely restates an aspect of the company's basic rights under the Natural Gas Act, without adding thereto. Colorado Interstate must, and presumably will, act in good faith in attempting to make required additional gas available; no form of words to that effect in the tariff is needed. It is concluded that it is unnecessary and undesirable to spell out in more detail the procedure for attempting to make additional gas to customers available, or to add such further detail to paragraph 17.1(d) of Colorado Interstate's General Terms and Conditions.

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[9] The present or future history of Colorado Interstate customer service relations, much referred to but immaterial here, might be of importance in such proceedings.

Decreases In Contract Demand

Staff suggests that Section 17.2 of the tariff's General Terms and Conditions should be "liberalized to allow a permissive reduction of contract demand to those customers which have a substantial amount of military sales" (Br. 18). The Colorado PUC suggests that all customers should have "the right to decrease the then effective contract quantity by not more than five percent over the life of the service agreement" (Br. 20).

Under Section 17.2 as proposed by Colorado Interstate, "Buyer may decrease the Contract Demand" on one of two conditions, viz., either (a) when and to the extent that "the capacity so released can be made available to and offset by increases in the Contract Demand of other Buyers," or (b) "when and to the extent that Seller in its judgment can otherwise utilize the released capacity."

The factual background for the suggested revision is the existence in the Colorado Springs area of a large military installation (Fort Carson) which might be abandoned or reduced in size at some indefinite time in the future. Such an occurrence would substantially reduce the contract requirements of the City of Colorado Springs and Plateau Natural Gas Company.

The Colorado PUC points out that percentage-wise its revision would not cast a large burden on Colorado Interstate or its other customers, since any buyer reducing its volumes would still be obligated to pay at least 90 percent of 95 percent of the prior (higher) Contract Demand. Cf. *e.g.*, Section 5 of Rate Schedule G–1.

Staff's proposed revision of Section 17.2 would as a matter of degree incorporate too much vagueness and uncertainty ("substantial amount of military sales") into Terms and Conditions which would be definite and concrete. In order to make an appropriately concrete revision to meet the Fort Carson stipulation, the new provision would have to define with particularity the "military sales" which, when and if curtailed, would give the customer the right to decrease its Contract Demand. Such a revision, however, would not really be in the nature of a General Term and Condition to a tariff of uniform application, but would have to be a special one-company tariff predicated upon findings that Colorado Springs is a unique customer. The facts do not support such findings. Colorado Springs is a growing market. If and when Fort Carson is likely to be abandoned, with adverse effects on the Colorado Springs distributors, such distributors will no doubt come in for appropriate relief on an adequate factual presentation.

The suggestion of the Colorado PUC would entitle any or all of Colorado Interstate's customers to one five percent decrease in Contract Demand over the (20-year) life of the service agreement. Of such a uniform provision, Colorado Interstate's vice-president cogently says (Tr. 285–286):

> * * * the 5 percent decrease in their case would amount to 24 percent, as I have already testified, of all our remaining customers' requirements. We are entitled to recover our cost of service, and if such a decrease required the filing by us of a rate application all of our customers would have to pay for the decrease in capacity by one customer. Secondly, we have no control over our customers' estimates. They are going to make the estimates and we are going to do our best to meet them. As you realize, that requires long-term gas contracts. It may require considerable facilities, and once having done so and changed our position to meet estimates of customers, we should not be required to take on the burden if some of those estimates are not realized. Thirdly, as the situation stands now we are not insulated in any respect because of the provisions of this tariff. The minimum bill

> provisions will return us about 30 percent of our total jurisdictional cost of service. We have no requirements on annual takes, total takes, either on an annual or monthly basis, and if for some reason our customer's business falls off we are going to feel it just as much as they do. I might sum up by saying that in many respects this reduction provision to me seems somewhat illusory. As long as we are permitted to get our cost of service, it might possibly shift costs from one customer to another, but over-all it would not save any customer any money in the long run.

It is uncontroverted that a number of major pipeline tariffs contain no provision at all for decreasing the Contract Demand, and that of those tariffs making such provision, the majority are in terms generally similar to the terms of Section 17.2.[10] On the other hand, two pipeline components of the Columbia System authorize their buyers to make two successive annual five percent reductions in Contract Demand, and further reductions provided that the capacity so released can be otherwise used by the pipeline seller. *Central Kentucky Natural Gas Co. et al.*, 15 FPC 700, 715, 730, 731 footnote 2.

The problem of what is equitable, in regard to this highly speculative future risk, cannot be resolved by application of rules or principles since there is no basis for a general rule or principle. In the *Central Kentucky* case just cited, the Commission, after discussing the benefits of the Contract Demand rate form, continued (15 FPC at 732)—

> Yet, the CD rate form does not impose an undue burden upon the distribution company customers. Considerable leeway is granted in the 90 percent ratchet provision. Furthermore, the billing demand may be reduced to 81 percent of the contract amount nominated through two successive 5 percent reductions. * * *

Thus, the Commission has specifically given favorable notice in one case to a provision for a small reduction of Contract Demand at the buyer's option. However, in all other cases, no such provision was apparently sought, and no such provision was required. On balance, there is insufficient showing that a general permissive reduction should be required in the tariff at bar. The arguments to the contrary focus on the generality that some of the risks of cold weather (high peak days) are being assumed by Colorado Interstate's customers under the new Contract Demand tariff form. The generality is true, but irrelevant.

Colorado-Wyoming Gas Co. Billing

Pursuant to notice given by Colorado Interstate under the new tariff, Colorado-Wyoming's Contract Demand was established as 137,700 Mcf, effective June 1, 1960. Under the applicable new P–1 Rate Schedule, the Billing Demand payable by Colorado-Wyoming is the highest day's delivery during the twelve months ended with the current billing month, but not less than 90 percent of the Contract Demand nor more than the Contract Demand. On February 27, 1960, Colorado-Wyoming had taken 138,673 Mcf. On the basis that the highest day's delivery during the prior period thus exceeded the specific Contract Demand, Colorado Interstate computed Billing Demand for the period June 1, 1960, to January 1, 1961, on the Contract Demand figure of 137,700 Mcf.

Colorado-Wyoming claims that this computation is incorrect. Colorado-Wyoming reasons that since the new tariff effective June 1, 1960, brought into being an entirely new set of circumstances, unrelated to the past, the use of its

[10] The tariffs of Northern Natural Gas Co., Mississippi River Fuel Corp., Southern Natural Gas Co., and Texas Gas Transmission Corp., require that decreases be predicated on seller's ability to dispose of the capacity, as here. (Tr. 223.)

February 27, 1960, actual "take" of gas in computing Billing Demand was retroactive and improper. Colorado-Wyoming contends that 90 percent of the 137,700 Mcf Contract Demand, or 123,930 Mcf, should be its Billing Demand for the period in question.[11]

From the Colorado Interstate "Statement of Revenues Subject to Further Order" in the docket at bar, heretofore referred to, we may first note the revenue effect of the Colorado-Wyoming contention.

For the period June through December 26, 1960, in question, revenues to Colorado Interstate would amount to $822,795 if the contention were allowed, as compared to $906,066 as computed and collected by Colorado Interstate. It is important to note that this last figure is very close to the amount, $915,792, which would have been realized under a continuation of the old tariff.

To January 31, 1962, counting realizations for the June-December 1960 period as computed and collected by Colorado Interstate, the new tariff as applied to Colorado-Wyoming has brought $28,710 less revenues to the supplier than revenues would have been under the old tariff. Related to collections totalling $935,739, this is a comparatively insignificant difference.

On the facts, then, acceptance of the Colorado-Wyoming contention would result in a level of rates payable by it to Colorado Interstate which would for the period June 1–December 31, 1960, be considerably lower than the level agreed upon in the settlement described in the opening paragraphs of this opinion. Certainly, in entering and approving the settlement, neither the participants nor the Commission contemplated a $92,997 windfall resulting to Colorado-Wyoming.

The change in rate form is not, as a matter of law under the applicable Commission and other authority, a basis for the results claimed by Colorado-Wyoming. The new Contract Demand form of rates, in presently pertinent part, was intended only to restate the revenue realizations under the prior rate form effective before June 1, 1960. It has accomplished this result under Colorado Interstate's use of the immediately prior period in the determination of Colorado-Wyoming's billing demand. The Colorado-Wyoming contentions on this issue are therefore disallowed.

Unexecuted Service Agreements

The Public Service group of companies and Citizens Utilities Company have not executed the new form of service agreement which is a part of the new tariff. These companies still operate vis-a-vis Colorado Interstate on the basis of contracts executed in the late nineteen forties. All these companies have established and changed from time to time their Contract Demand quantities, pursuant to agreements with Colorado Interstate.

Questions of general importance are raised by the Colorado PUC, the Public Service group, and the Staff concerning the present vitality and the public interest aspects of the old contracts. Broad issues of substance between Colorado Interstate and its customers are alluded to in the briefs in this proceeding as to whether (a) such customers must execute new service agreements, or may rely on their old contracts under the *Mobile* rule (*United Gas Pipeline Co.* v. *Mobile Gas Service Corp.*, 350 U.S. 322); (b) Colorado Interstate has violated the Act by failing to file certain letter agreements with its customers establishing their initial contract demand quantities; (c) the old contracts are discriminatory.

[11] Beginning December 26, 1961, Colorado-Wyoming's contract demand was raised to 158,000 Mcf, and therefore its contention relates only to the period June 1—December 26, 1960.

These questions are abstract, and do not involve actual dollars-and-cents current issues between Colorado Interstate and its customers. The questions have not ripened into actual controversies between the pipeline and the distributors, or other conflictual situations properly basing complaints or investigations. The facts behind the questions were not substantially developed in the record herein. The questions are not properly presented on brief herein.

Under the order authorizing the proceeding at bar, the issues are limited to the propriety of Colorado Interstate's form of tariff, including the "lawfulness of the rates, charges, classifications, and services contained" therein.[12] In pertinent part, that tariff contains a form of service agreement. Section 154.13 of the Regulations Under the Natural Gas Act provides that:

> The term "service agreement" means an unexecuted form of agreement for service under a natural-gas company's tariff.

The form of unexecuted service agreement presented conforms to such regulations (Sections 154.14, 154.38(3), and 154.40) as is uncontroverted. No other issue in this connection was authorized to be litigated, or was actually litigated, in the proceeding at bar. No opinion is or should be expressed herein on the questions mentioned in the foregoing section of this opinion.

Boiler Fuel Sales

Colorado Interstate sells gas directly, and not under any FPC tariff, to Public Service Co. of Colorado, City of Colorado Springs, and City of Trinidad for use in firing boilers in the electric generating plants of these customers. The gas is priced at 21.5 cents per Mcf. If the customers could buy the gas under their G–1 Rate Schedules, the price would be 18.5 cents per Mcf. The situation existed under Colorado Interstate's old tariff, and is continued in the new tariff because no special new provision is written therein to allow for gas consumed in the generation of electricity.

The City and County of Denver, but none of the mentioned customers, claims that the Commission should in this proceeding require such a special new provision as an incident of the Colorado Interstate change in rate form. Denver claims discrimination and prejudice to the customers' load factor resulting from continuation of the direct sales method of boiler fuel supply; Colorado Interstate claims that the suggested change would impair its own load factor and is beyond the Commission's jurisdiction.[13]

The record does not contain the facts as to how the direct sale connections and capacity to serve the same were constructed by Colorado Interstate, nor the facts on which the jurisdictional or nonjurisdictional character of the sales could be determined in this proceeding. Such facts would not properly be a part of this record, because we are not here considering substantive complaints about Colorado Interstate's methods of doing business with its boiler fuel customers and we are not engaged in a general investigation of Colorado Interstate's jurisdictional business with the named three customers or other customers.[14] The issues in the proceeding at bar relate only to the proper

[12] In regard to rates, charges and classifications, dealt with in prior sections hereof, note that because of the settlement of Docket No. G–13541 "the proposed tariffs represent a filing relating to rate form, not to rate level." Order of August 16, 1960, herein.

[13] Citing *Colorado Interstate Gas Co.* v. *F.P.C.*, 185 F. 2d 357 (CA3), and *Colorado Interstate Gas Co.*, 19 FPC 1012, 1022, rehearing granted and settled, 20 FPC 70.

[14] Were issues of substance involved, load factor of customer companies and other consumer considerations would be of high importance. See *Southern Natural Gas Co.*, 25 FPC 925, 931 *et seq.*

translation of Colorado Interstate's former tariff into a contract demand tariff producing revenues at Commission-approved settlement levels. We now deal only with the formal aspects of Colorado Interstate's new tariff, and should express no opinion as to the jurisdictional or nonjurisdictional character of the boiler fuel sales made by this natural gas company to the Public Service Company, City of Colorado Springs, and City of Trinidad.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission, that:

(A) The objections to Colorado Interstate Gas Company's FPC Gas Tariffs, First Revised Volume No. 1 and Second Revised Volume No. 2, are hereby dismissed.

(B) The undertaking to assure refunds of excess charges entered into by Colorado Interstate Gas Company pursuant to order of the Commission issued June 14, 1960, is hereby discharged.

(C) This proceeding is hereby terminated.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

CONTINENTAL OIL COMPANY, DOCKET NO. G–15571

ORDER GRANTING EXTENSION OF TIME

(Issued June 1, 1962)

By its order issued March 5, 1962, in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, 27 FPC 441, the Commission disposed of more than 400 proceedings, including that above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. With respect to the instant docket, ordering paragraph (A) of the March 5 order directed Continental Oil Company (Continental) to refund tax-reimbursement amounts collected from its direct customer Transcontinental Gas Pipe Line Corporation (Transco). Ordering paragraph (C) of the March 5 order directed that within 90 days from the date of issuance thereof, Continental report to the Commission the details of its refund calculations and submit copies of releases from Transco as to the required refunds. By order issued April 26, 1962 in *Texaco Inc., et al.*, Docket Nos. G–155546, *et al.*, 27 FPC 847, the Commission denied applications for rehearing of the March 5 order in the above, as well as other, dockets. On May 29, 1962 Continental filed a motion seeking to stay the effectiveness of the March 5 order, insofar as applicable to the above docket, until 30 days after conclusion of judicial review of said order in that docket. The motion recites that Continental intends to seek judicial review of the March 5 order and that failure of the Commission to grant the stay pending such review would cause it irreparable injury.

For reasons stated in our order of April 13, 1962 granting Pan American Petroleum Corporation and extension of time for compliance,[1] we are disposed to extend the time within which Continental must comply with ordering para-

[1] Pan American Petroleum Corporation, Docket No. G–15641; Pan American Petroleum Corporation (Operator), *et al.*, Docket Nos. G–15650 and G–15780, 27 FPC 686.

graphs (A) and (C) of the Commission's March 5 order, for a period ending 30 days after conclusion of judicial review of that order in the instant docket.[2] The extension is conditional, however, upon the payment by Continental to Transco of interest, at a rate of 7%, upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the order of March 5.

The Commission finds:

(1) There is good cause for extending the time within which Continental must comply with the requirements of ordering paragraphs (A) and (C) of our order of March 5, 1962, for a period ending 30 days after conclusion of judicial review of that order in the instant docket.

(2) It is just and reasonable and in the public interest that Continental be required to pay Transco interest, at a rate of 7% upon the amounts to be refunded, for the period commencing on the 91st day after issuance of the March 5 order.

The Commission orders:

(A) The time within which Continental must comply with ordering paragraphs (A) and (C) of the Commission's order of March 5, 1962 is extended for a period ending 30 days after the conclusion of judicial review of the Commission's order.

(B) Continental shall pay Transco interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the March 5, 1962 order.

(C) The time within which Transco must comply with ordering paragraphs (B) and (D) of the March 5, 1962 order, insofar as applicable to the instant docket, is extended for a period ending 60 days after conclusion of judicial review of that order in said docket.

(D) If Continental shall not have filed petitions for review of the March 5 order in the instant docket within the 60 day period prescribed by statute, the extension of time herein granted shall be deemed inoperative and of no effect.

HUMBLE OIL & REFINING COMPANY, DOCKET NO. CI62-627

ORDER ADOPTING AND MODIFYING DECISION OF PRESIDING EXAMINER

(Issued June 1, 1962)*

Syllabus

1. It is unnecessary here to determine whether there are circumstances in which stock acquisition of one natural gas company by another would constitute, or be part of, acquisition of facilities under Section 7(c) of the Act, or explore reach of dictum in *California v. F.P.C.*, raising question of existence of such authority. P. 1079.
2. Commission *finds* it has no jurisdiction over stock acquisition as such, and could at most reach such purchases where they are an integral part of transaction in which stock purchase is to be followed either by "consequent

[2] It should be understood that the 30th day after judicial review in the instant docket is the date upon which Continental must comply with the March 5 order; it is *not* the date upon which the 90 day period referred to in ordering paragraph (C) commences to run.

* Initial decision appears on P. 1080.

transfer of assets from the acquired subsidiary to the acquiring parent," *California v. F.P.C.*, 295 F.2d 348, or integration with acquiring corporation. P. 1080.

3. Commission *holds* that stock acquisition here is not preliminary to a facility acquisition upon which it will be called to pass, whose terms and consequences should not be ignored in exercise of its responsibilities under Sec. 7(c) of the Act. P. 1080.
4. In light of evidence as to future operation of acquired jurisdictional facilities, Commission *finds* it is without jurisdiction to determine whether such acquisition is in public interest. P. 1080.
5. Commission *concludes* it does not have jurisdiction over Humble's acquisition of stock and *terminates* proceeding initiated under Sections 14, 15 and 16 of the Natural Gas Act. P. 1080.

Carl Illig, Jesse H. Foster, Jr., and *Bernard A. Foster, Jr.* for Humble Oil & Refining Company.

David S. Lichtenstein for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

On December 13, 1961, 26 FPC 854, the Commission issued an order requiring Humble Oil and Refining Company (Humble) to show cause why it should not file an application for a certificate of public convenience and necessity pursuant to Section 7(c) of the Natural Gas Act to acquire by stock ownership the facilities of Olin Gas Transmission Corporation (Transmission). On January 16, 1962, Humble filed a motion to terminate the proceeding and dismiss the Commission's order on the ground that the acquisition of all outstanding stock of Olin Gas Transmission by Humble does not constitute an "acquisition of facilities" within the meaning of Section 7 of the Natural Gas Act. On February 5, 1962, the Commission denied the motion for termination without prejudice. A hearing on the order to show cause was held before a Presiding Examiner of the Commission.

The decision of the Presiding Examiner in the above proceeding was issued on May 14, 1962. Staff counsel has indicated by letter of May 29, 1962, that he will not file exceptions to the decision.

The Commission has considered the entire record before the Presiding Examiner and concludes that the order to show cause should be dismissed. It was clearly stated by the Commission at the time of issuance of the order to show cause that the proposed acquisition of the facilities of Transmission through ownership of all of the outstanding stock of that company *may be* subject to the Commission's jurisdiction under Section 7(c) of the Act. We recognized the difficulty of any a priori determination of whether a proposed acquisition of facilities through stock control should be subjected to the surveillance of the Commission.

The Examiner has found that Humble will have as complete control of Transmission's facilities indirectly through the ownership of the latter's stock as it would have were it purchasing the facilities directly. In short, Transmission will be controlled and operated virtually as a Humble subsidiary. Nevertheless, the Examiner concluded on the basis of his independent reading of Section 7(c) of the Natural Gas Act that the Commission has no jurisdiction over this or any other stock acquisition.

We do not believe it necessary to the resolution of the present case to determine whether there are any circumstances in which an acquisition of stock of one natural gas company by another would constitute, or be part of, an acquisi-

tion of facilities within the meaning of Section 7(c) of the Natural Gas Act, or to explore the reach of the dictum in *California* v. *Federal Power Commission*, No. 187, Oct. term, 1961, which raises questions of the existence of any such authority. For we think it clear that the Commission has no jurisdiction over stock acquisition, as such, and could at most reach such purchases where they are an integral part of a transaction in which the stock purchase is to be followed either by a "consequent transfer of assets from the acquired subsidiary to the acquiring parent", *California* v. *Federal Power Commission*, 296 F. 2d 348, or integration with the acquiring corporation. There is no evidence, however, that this is the situation here or that Humble has any present intention of utilizing its stock ownership of Olin to acquire Olin's facilities for use as part of Humble's existing jurisdictional business or otherwise to terminate the existence of Olin as an operating company fully subject to our jurisdiction. The stock acquisition herein is thus not preliminary to a facility acquisition upon which we will be called to pass, whose terms and consequences should not be ignored in exercising our responsibilities under Section 7(c) of the Act.

Since we find that under the facts of this case, we have no jurisdiction to pass upon the Humble acquisition of Olin's stock we do not believe it appropriate either to affirm or reject the examiner's further finding and conclusion that if a certificate of convenience and necessity were necessary under the provisions of Section 7(c), Humble would be a qualified applicant able and willing to do the act proposed and that the acquisition will not impair competition and is or will be required by the present or future public convenience and necessity. Our failure to affirm these findings should not of course be taken as any indication that we would necessarily reach any different conclusion if the matter were properly before us.

The Commission finds:

In light of the evidence as to the future operation of the jurisdictional facilities acquired by Humble herein the Commission is without jurisdiction to determine whether such acquisition is in the public interest.

The Commission orders:

The order to show cause issued by the Commission on December 13, 1961, should be, and hereby is, dismissed.

DECISION

UPON ORDER TO SHOW CAUSE

(Issued May 14, 1962)

MARSH, *Presiding Examiner:* This is a proceeding upon an order to show cause issued by the Federal Power Commission on December 13, 1961, 26 FPC 854, directing Humble Oil & Refining Company (Humble or Respondent) to show cause, if any there be, why it should not be required forthwith to comply with all of the provisions of the Natural Gas Act, including particularly Section 7(c) thereof[1] and why it should not file an application for a certificate of public convenience and necessity to acquire by stock ownership the facilities of Olin Gas Transmission Corporation (Transmission) as more particularly hereinafter

[1] The relevant portions of which are as follows:

"No natural-gas company * * * shall engage in the transportation or sale of natural gas, subject to the jurisdiction of the Commission, or undertake the construction or extension of any facilities therefor or acquire * * * any such facilities * * * unless there is in force with respect to such natural-gas company a certificate of public convenience and necessity issued by the Commission authorizing such acts or operations. * * *"

described. The order directed that a public hearing be held beginning on March 27, 1962.

Appearing specially and solely in response to the Commission's "Order to Show Cause and Fixing Date of Hearing," issued on December 13, 1961, Humble filed on January 16, 1962, a response to the order of December 13, 1961, in which the Respondent asked alternatively that (1) the Commission terminate its show-cause proceeding and issue an order declaring that Section 7(c) of the Natural Gas Act does not require Humble to obtain a certificate of public convenience and necessity before acquiring all of the outstanding capital stock of Transmission; (2) the Commission issue forthwith a certificate of public convenience and necessity authorizing Humble to acquire all of the outstanding capital stock of Transmission if such a certificate is deemed required by Section 7(c). Humble requested therein that the Commission advance the date of hearing to February 19, 1962.

On February 5, 1962, 27 FPC 193, the Commission issued an order denying without prejudice the motion just referred to but advancing the hearing date to March 2, 1962. No persons other than Humble and the Staff of the Commission sought the right, or were authorized, to participate in the proceeding. Pursuant to the order of February 5, 1962, the matter came on for hearing and was heard beginning on March 2, 1962, and concluding on March 22, 1962, with the undersigned presiding. Thereafter, briefs were filed by Humble and by Staff counsel and the matter is now ready for decision. At the conclusion of the hearing Humble renewed its motion to terminate these proceedings for lack of jurisdiction. Humble also asked, but only if Section 7(c) of the Natural Gas Act lawfully requires it, that the Commission grant to Humble a certificate of public convenience and necessity authorizing it to acquire all of the outstanding capital stock of Transmision "conditioned so as to assure that Humble shall not thereby be subjected to any of the Commission rules, requirements or regulations other than those now applicable to Humble as an 'independent producer.'"

The Proposed Acquisition

Humble proposes to acquire all of the assets, properties, privileges, franchises and business of Olin Oil & Gas Corporation (Olin Oil) including, without limitation, all of the outstanding stock of Transmission and with certain limitations, all of Olin Oil's debts and liabilities existing as of the closing date. However, Transmission would continue to exist as a corporation and would continue as such to own all of the facilities which it presently owns and operates. The acquisition would be accomplished by the transfer to Olin Oil of a number of whole shares of the capital stock of Standard Oil Company (New Jersey) equal in value (based on the closing price on the New York Stock Exchange on November 13, 1961) the sum of $68,054,056.[2] The transaction contemplates the redemption by Olin Oil of the 49,325 shares of its four percent preferred stock, Series A, plus accrued dividends, if any. Olin Oil would then distribute the stock received by it to its stockholders entitled thereto in exchange for the stock of Olin Oil and then dissolve and terminate its corporate existence.

In the contract of purchase and sale Humble agreed that immediately after the closing date it would cause the name Olin Gas Transmission Corporation to be changed to a name not including the word "Olin." The obligations of the parties to the "agreement and plan of reorganization" are subject to the condition, among others, that:

[2] The reason why the acquisition was to be accomplished by means of Standard Oil Company stock rather than cash was because this procedure makes a non-taxable transaction for the seller.

> The Federal Power Commission shall have found that it does not have jurisdiction over the transactions contemplated by this Agreement, or in the alternative, the Federal Power Commission shall have granted a certificate of public convenience and necessity satisfactory to Humble with regard to the transactions contemplated by this Agreement.

Olin Oil agreed to cause a meeting of its stockholders to be held not later than May 31, 1962, for the purpose of authorizing the conveyance to Humble and the voluntary dissolution of Olin Oil. The closing date was to be fixed by the mutual consent of the parties to the agreement but in no event subsequent to July 31, 1962.

The Parties to the Proposal

Transmission is a corporation organized under the laws of the State of Delaware and it has its principal place of business in New Orleans, Louisiana. Transmission is a natural-gas company[3] within the purview of the Natural Gas Act and is, therefore, subject to the jurisdiction of this Commission. *Olin Gas Transmission Company*, 17 FPC 685, 1959. Transmission is the wholly owned subsidiary of Olin Oil. Olin Oil was the wholly owned subsidiary of Olin Industries, Inc. (Olin).[4]

Olin Oil's principal assets consist of all of the outstanding capital stock of Transmission, and mineral interests consisting of producing properties and undeveloped leases located principally in the States of Arkansas, Louisiana and Oklahoma.

In 1960 these mineral holdings totaled approximately 510,000 acres. The principal fields in which Olin Oil owned producing wells as at December 31, 1960, were located in Okfuskee County, Oklahoma, Lafourche, Lafayette, Vermilion, Catahoula, and Union Parishes, Louisiana and Union and Bradley Counties, Oklahoma. The evidence is that most of the production from this acreage consists of crude oil. What gas is produced therefrom comes principally from the oil wells and is sold not in interstate, but in intrastate, commerce. Olin Oil's 1961 budget amounted to $5,679,000 which included $2,939,000 for exploration, $1,711,000 for exploitation (pool development) and $1,029,000 for fixed capital additions to the capital system.

As of December 31, 1960, Olin Oil had outstanding 49,325 shares of four percent cumulative Series A preferred stock which was recorded on the company's books at $2,466,250, and 2,829,628 shares of common stock of a par value of $1 per share. Long-term debt (less current portion—$1,778,000), represented by a 4½ percent note (to Prudential Insurance Company), amounted to $17,776,000. Paid-in surplus was $8,183,267 and earned surplus was $9,008,669. In 1954 the debt to equity relationship for Olin Oil was 31 to 9.6 whereas in 1960, it was 19.6 to 22.5, or approximately one to 1.15. Olin Oil had paid no dividends until 1959 and since then there has been a yield of only approximately 2½ percent on the stockholders' investment. During the years 1954 through 1961 Olin Oil's common stock has ranged in market price from a low of $13 to a high of $32 per share.

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[3] Through intercorporate transactions Transmission became in 1954 the owner of the facilities and business of Interstate Natural Gas Company, Inc., a natural-gas company. On April 30, 1954, at Docket No. G–2335, 13 FPC 1012, the Commission authorized the acquisition and operation by Transmission of Interstate's facilities subject to certain conditions.

[4] The evidence shows that "on January 22, 1954, substantially all of the outstanding capital stock of Olin Oil & Gas Corporation was distributed ratably to the holders of the outstanding capital stock of Olin Industries, Inc. There is today no corporate tie or connection between either Olin Oil & Gas Corporation or Olin Gas Transmission Corporation and any successor to Olin Industries, Inc."

Transmission is engaged in the production and purchase of natural gas, in the gathering and transportation of such gas and in the sales and deliveries thereof. In 1960 this company owned and operated approximately 763 miles of gas transmission lines having a capacity of about 550,000 Mcf per day. In addition, Transmission operates 364 miles of gathering lines in which its interest ranges from seven percent to 100 percent. It also owns an operating interest of approximately 10 percent in an intrastate natural gas transmission system in the vicinity of New Orleans which is operated by United Gas Pipe Line Company. In addition, Transmission had in 1960 mineral interests in approximately 89,000 gross acres of lands lying principally in Arkansas, Louisiana and Texas. Natural gas is transported by Transmission from the Monroe and various other natural-gas fields in Louisiana to markets where it is sold at wholesale under long-term contracts to large industries, municipalities and pipeline companies.

The transmission facilities operated by Transmission presently comprise three separate systems, one of which is characterized as "jurisdictional" and the other two as "non-jurisdictional." With the exception of about 103 miles of transmission lines lying within the State of Mississippi, all of Transmission's facilities are within the State of Lousiana. The first of the three systems extends in a southeasterly direction from the Monroe field in north central Louisiana to a point on the Mississippi River (the Louisiana-Mississippi boundary) near Natchez, Mississippi. From thence it extends in a southerly direction through the State of Mississippi reentering the State of Louisiana at a point about five miles west of the Helena Meridian. From that point it continues in a southerly direction to Baton Rouge, Louisiana. These facilities were constructed by Transmission or its predecessor in interest. They are concededly employed for the transportation in interstate commerce, and the sale in interstate commerce, of natural gas for resale. Total sales from these facilities in 1960 amounted to 40,217,140 Mcf.

The Monroe-Baton Rouge system is not interconnected with either of the other two systems. Sales for resale in interstate commerce from the Monroe-Baton Rouge line in 1960 amounted to 9.4 million Mcf or six percent of Transmission's total transmission sales in that year of 157.2 million Mcf. In 1961 the total transmission sales from that system were 152.7 million Mcf of which about 9 million Mcf were jurisdictional.

Total purchases for the interstate system in 1960 were 16,859,624 Mcf. Transmission produced in that year in the Monroe field 23,493,000. The total sales from the interstate line in 1960 were about 40,217,140, which represents about 25 percent of Transmission's sales. Humble sold Transmission 671,948 Mcf during 1960 and purchased from that line 5,071,672.

Production from the Monroe field is available only to the Monroe-Baton Rouge system and is the principal source of supply for that system. The testimony is that the Monroe field is a very rapidly depleting field. There are in the Monroe field many producers but there is with respect to the field no requirement or provision for ratable takes therefrom. In 1954 Transmission owned and operated in the Monroe field 339 wells which were capable of producing at a rate of 99,142 Mcf per day. In 1961 those wells were producing at a rate of only 48,040 Mcf a day. In 1961 all of Transmission's wells in the field, then 473 in number, were capable of producing only 80,213 Mcf a day, which was substantially less than the 99,142 Mcf per day which the 339 were capable of producing six years earlier. Even though 134 additional wells were drilled during the period 1954 to 1961 the production rate at the beginning of 1954 was not equaled in 1961. Obviously, unless some new supply of gas should become

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available to the Monroe-Baton Rouge system it will be unable to supply any substantial new customers.

Another of Transmission's systems, referred to as the Baton Rouge-West system, extends in a westerly direction from Baton Rouge to the North Tepetate field with a line extending therefrom in a southerly direction to the Pecan Island field. This system gathers and transports gas from southern Louisiana fields. About 83.8 billion cubic feet of gas was transported through these lines in 1960.

The Baton Rouge-South system extends in a southerly direction to the Sweet Bay Lake field. This system is supplied by reserves from south central Louisiana fields. About 38.1 billion cubic feet were in 1960 transported through that system.[5]

The testimony is that during 1960, approximately 124,000,000 Mcf of gas was transported through the three above described systems and other smaller non-jurisdictional facilities. This volume represented about 80 percent of all gas transported through facilities operated by Transmission. In 1961 the comparable volume was 123,000,000 Mcf and the comparable percentage was 81 percent. On the other hand, the testimony is that in 1961 only about 32 percent of the gas transmitted through the jurisdictional system was sold for resale and, therefore, that only about six percent of the total volume of gas transported by Transmission was subject to the jurisdiction of this Commission. Over 90 percent of the 1959 volumes of gas sold from the three systems was sold to large industrial consumers.

Of all the gas sold by Transmission in 1954, it produced about 25 percent and purchased about 75 percent. In 1959 Transmission produced about 14 percent of its requirements and purchased the remainder from others.

In 1960 Olin Oil and Transmission together drilled a total of 12 gross exploratory and 80 gross development wells in the United States, 63 of which were in Louisiana. Of the Louisiana wells, 29 were drilled in the Monroe field. The two companies drilled or participated in the drilling of a total of 76 net wells.

Total purchases for the jurisdictional systems in 1960 were 16,859,624 Mcf. Transmission produced in the Monroe field for that year about 23,493,000 Mcf so that the total intake of the jurisdictional line, including gas purchased and produced by Transmission amounted to some 40,000,000 Mcf. Sales of the jurisdictional line for 1960 were likewise about 40,000,000 Mcf, or about 110,000 Mcf average daily. This represents approximately 25 percent of the total volume of sales of Transmission.

Humble supplied the jurisdictional line with 671,948 Mcf during 1960 and purchased in that year 5,071,672 Mcf from the Monroe line. Humble's total purchases from Transmission, including the jurisdictional and non-jurisdictional systems in 1960 amounted to 64.9 million Mcf.

Humble is a corporation organized under the laws of the State of Delaware and it has its principal place of business at Houston, Texas. This corporation is a wholly owned subsidiary of Standard Oil Company (New Jersey). Its assets totaled over $3 billion at the end of 1960 and it had a debt to equity ratio of $44.1 million to $2,664.6 million, or approximately one to 60. The Respondent is authorized to do business in each and all of the United States and in the District of Columbia. Humble is engaged in all phases of the petroleum business throughout the United States including exploration for and the production, refining, distribution and sale of oil and gas. Humble owns and operates a refinery at Baton Rouge, Louisiana which refines crude oil into various products and which produces petro-chemical products from hydro-

[5] Another 2.2 billion cubic feet were transported through the Natchez-East system.

carbons. Humble also manufactures, distributes and sells petroleum products derived from oil and gas. It operates extensive research facilities conducting diversified research through the petroleum industry. The Respondent rank as a leader in the United States in the production of crude oil and natural gas, in the refining of crude oil into refined products, in the sale of natural gas and petroleum products, and in other phases of the petroleum business.

Humble is an independent producer of natural gas as defined in the Commission's Regulations for natural gas companies and is, therefore, a natural-gas company as defined in the Natural Gas Act. Thus, Humble is subject, as an independent producer, to the jurisdiction of the Federal Power Commission. Humble's net jurisdictional sales in 1960 involved approximately 212,000,000 Mcf involving total revenues of $33,2 million.

Traditionally, Humble has carried on large exploration and development operations in Louisiana and Mississippi. The Respondent owns lease interests in Bossier, Webster, Claiborne, Lincoln, Bienville, Ouachita and Tensas Parishes in northern Louisiana, and a large number of such lease operations in south Louisiana. Humble also owns interests of this kind in Jefferson and Adams Counties in Mississippi. In 1960 Humble produced approximately 163 billion cubic feet of gas and approximately 24 3/10ths million barrels of oil and condensate from wells in Louisiana. In the same year, Humble drilled or participated in the drilling of some 23 net exploration wells and some 132 net development wells in Louisiana at a total direct cost of over $49,000,000.

Humble is a substantial supplier of natural gas for Transmission from various fields in Louisiana and Mississippi. The Respondent is the purchaser of substantial volumes of natural gas from Transmission principally for use in Humble's Baton Rouge refinery. In 1960 Humble supplied about 32,300,000 Mcf to Transmission and purchased from Transmission about 64,900,000 Mcf.

Humble has properties in nearly all areas in which Transmission buys gas but Humble has no uncommitted gas reserves of any significant size located close to Transmission's pipelines.

Humble owns and operates a small gas pipeline five miles in length which extends from the Lirette field in Terrebonne Parish to Montegut. The line serves only a sugar mill which buys about 700 Mcf a day. Respondent owns all of the stock of a small gas pipeline system extending from the Lake Boeuf field to a point, near Gramercy in St. James Parish, a distance of approximately 30 miles away. Humble also owns 48 percent of the stock of a company which proposes to own and operate a gas transmission system from the King Ranch Plant near Kingsville in southwest Texas to Alexandria, Louisiana, at which point it would sell gas to United Fuel Gas Company. None of the pipeline systems which Humble owns or operates, or in which it owns stock, purchase gas from the same fields as does Transmission.

Humble proposes that Transmission shall continue to exist and be operated as a separate corporate entity; that it will continue to have its own separate management and its own employees. It is not proposed that Transmission abandon any of its facilities but that it continue to serve all of its present customers and make every effort to add new ones and expand the service.

The transaction here proposed does not involve a merger or combination of any of the facilities of Transmission with those of Humble. Nor is it proposed or anticipated that Transmission will abandon any facilities or services. On the contrary, it is expected that Transmission's facilities and operations will be expanded.

Humble regards the acquisition of Transmission's stock as an investment in the gas transmission business. Respondent expects that it can obtain a reason-

able return on the money it proposes to invest through continued operation of the producing properties, the development of undeveloped leases and through dividends on the stock in Transmission. One of Humble's reasons for acquiring the assets of Olin Oil is to obtain the latter's undeveloped properties.

The Benefits Expected

Benefits expected to result to the public from the acquisition by Humble of the common stock of Transmission are:

1. The financial strength of Humble will better enable Transmission to finance effectively and, thereby, will benefit the latter's customers and the public.

2. The "know-how" possessed by Humble personnel in the business of producing, processing and transportation of natural gas would be available for the use of Transmission.

3. Humble's engineering staff and research facilities would be available for consultation.

4. The large number of persons employed by Humble would afford a pool from which Transmission might recruit needed key personnel.

5. Humble's knowledge and experience respecting existing reserves of gas and future exploration prospects will be available to Transmission.

6. Transmission's relationship to Humble should enable the former to better compete with other purchasers in negotiations leading to the purchase of additional supplies of gas.

7. It is asserted that Transmission's present jurisdictional rates are lower than the area prices fixed in the Commission Policy Statement No. 61-1 for south Louisiana. The advantages which the acquisition of the stock of Transmission by Humble would afford the former would tend to offset pressures to increase rates.

8. Through affiliation with Humble, Transmission should have greater flexibility in obtaining new supplies for its system.

These factors, Staff counsel concedes, should ultimately benefit the consumer of natural gas. The evidence unquestionably shows that if the acquisition were consumated certain benefits would accrue, at least some of which should flow through to Transmission's customers.

What of Detriments?

Assuming that the Commission has jurisdiction in the premises, a question which will be considered later, is there an adverse impact upon the public interest which outweighs those several benefits? The proposal here under consideration requires inquiry into whether there would result a conflict with the fundamental national policy expressed by the Congress in the anti-trust area. (*Cf. People of the State of California* v. *Federal Power Commission*, 296 F. 2d 348, 353) Thus, as is conceded by the Respondent, it is appropriate to inquire into any effect on competition stemming from Humble's acquisition of the stock of Transmission. There are, of course, in this context two aspects of competiton which require consideration, one, the competition between buyers for the purchase of natural gas and two, competition between sellers of natural gas. Either too much of the former or too little of the latter might well adversely affect the interests of the public and the ultimate consumers of natural gas.

The testimony here is that the acquisition by Humble of the stock of Transmission will have no impact on competition. Humble and Transmission do not presently compete in connection with the purchase or sale of natural gas. Trans-

mission will continue to be a purchaser of natural gas in its area of operations. Transmission purchases gas for its interstate operations from 10 suppliers, five of whom, including Humble, are major oil and gas companies, and one is a major oil pipeline company. Where Transmission buys over two-thirds of its purchased gas supply there are some 32 substantial purchasers of natural gas. Some of them are major interstate pipelines and others are large intrastate purchasers, which include industrial buyers and local pipeline systems. In north Louisiana there were in 1960 20 purchasers who purchased substantial quantities of gas there. Several pipelines purchase more gas in Louisiana than does Transmission. Humble purchases no gas in north Louisiana and is not a significant purchaser of gas from producers in the fields in south Louisiana. Humble has no uncommitted gas reserves of significant size located close to Transmission's system, nor does Humble have at the present time any substantial reserves which Transmission might expect to purchase. The testimony is that in no area can the acquisition of Transmission's stock by Humble adversely affect competition in connection with sales by producers. The evidence shows too that if any significant gas discoveries are made near the systems of Transmission, there will be prompt competition between pipelines to purchase that gas.

Many of the buyers of natural gas in north Louisiana now have, because, among other things of superior financial strength, an advantage over Transmission. The evidence shows as has been pointed out that the proposed acquisition will place Transmission in a better position to compete for additional supplies of gas. On the other hand, it shows too that Humble's financial resources would not give Transmission a potential competitive advantage over other buyers which might lead to the domination by Transmission of the Louisiana market in the future. In any event, Transmission must purchase gas on terms which are representative of market conditions.

There is no evidence here that Humble's acquisition of Transmission's stock will in any respect restrict or limit the ability of Louisiana producers to find markets for their gas. As has been said, Transmission will have to continue to purchase gas from others. Humble's acquisition of the stock of Transmission will not lessen competition by reducing the number of pipelines in the market for gas in the area. The small pipelines presently owned by Humble or its affiliates do not operate in the same areas as Transmission's.

So far we have considered only the evidence relevant to the effect of the acquisition upon competition under present conditions of facility ownership and operations. It is desirable to inquire, too, into the possible impact in the future of the proposed acquisition upon the public and the customers of both Humble and Transmission. In this connection, it should be repeated that both Humble and Transmission are "natural-gas" companies within the purview of the Natural Gas Act, Humble as an independent producer of natural gas and Transmission without qualification. Thus, the sales of gas in interstate commerce by either Humble or Transmission are subject to the jurisdiction of this Commission.

With respect to the ownership and operations of facilities with which Transmission engages in the transportation and sale of natural gas in interstate commerce, these facilities too are fully subject to regulation by the Commission.

In his brief, under the heading "Competitive Aspects of the Proposed Merger," Staff counsel asserts that:

> The prime business motivation for the merger apparently was to acquire the gas and oil producing assets of the parent corporation, Olin Oil & Gas. The pipeline apparently came along as part of the package.

Staff counsel found the danger of potential abuse of economic power which might arise from the acquisition so remote as not to warrant opposition to the granting of the certificate and, furthermore, that:

> * * * the evidence does not indicate that there will be any substantial lessening of competition as a result of the acquisition.
> We cannot, on the basis of mere conjecture as to potential abuse of economic power, oppose the acquisition of Transmission's facilities by Humble.
> It may also be noted in this case that the Commission will retain its surveillance over the jurisdictional line in terms of rates, services, etc.

Upon consideration of all of the evidence herein and the briefs filed, it is found and concluded, subject to a determination that a certificate of convenience and necessity as necessary under the provisions of Section 7(c), that Humble is a qualified applicant within the purview of Section 7(c), that the proposed acquisition is or will be required by the present or future public convenience and necessity, and that Humble is able and willing properly to do the acts proposed to be done in the premises.

Applicability of Section 7(c)

There remains for consideration, however, the question whether the proposed transaction requires a certificate of public convenience and necessity under the provisions of Section 7(c) of the Natural Gas Act. In its brief the Respondent states this issue as follows:

> (A) Does the Federal Power Commission have jurisdiction under Section 7(c) of the Natural Gas Act to require that Humble obtain a certificate of public convenience and necessity before it can acquire all of the outstanding capital stock of Transmission?

Humble then proceeds to argue that the Commission has no such jurisdiction. Nothing in Section 7(c), the Respondent contends, purports either expressly or implicity, to empower the Commission to control an acquisition of *stock*, as distinguished from the power granted to the Commission to control the acquisition of *facilities*. There follows an analysis of the Act, the legislative history of Section 7(c), the practice of the Commission, the decisions of the Supreme Court and the decision of the Court of Appeals for the District of Columbia in *People of the State of California* v. *Federal Power Commission*, 296 F. 2d 348, 1961, all of which appear to support the Respondent's contention that Section 7(c) conferred jurisdiction upon the Commission over the acquisition of *facilities* but not over the acquisition of *stock*.

If, then, the Respondent has correctly stated the jurisdictional issue involved in this proceeding, a certificate of public convenience and necessity authorizing the proposed transaction is not required.

But, it was asserted by the Commission in its order of December 13, 1961, that:

> * * * The proposed acquisition by Humble of the facilities of Olin Gas Transmission through the purchase of the assets of Olin Oil & Gas may be subject to the Commission's jurisdiction under Section 7(c) of the Act.

The word "stock" does not here appear. The order further recites that:

> Humble has not filed an application pursuant to Section 7 of the Natural Gas Act for permission to acquire the facilities of Olin Gas Transmission, which acquisition will result from the exchange of stock between Humble and Olin Oil & Gas.

The Commission then ordered that:

Humble Oil & Refinery Company shall show cause, if any there be, at the hearing directed in paragraph (B) hereof, why it should not be required forthwith to comply with all of the provisions of the Natural Gas Act, including, particularly, Section 7(c) thereof and why it should not file an application for a certificate of public convenience and necessity to acquire by stock ownership the facilities of Olin Gas Transmission.

This language is taken to mean that since the stock is merely the evidence of ownership, the practical effect of the acquisition thereof is the acquisition of the facilities themselves. Thus, the jurisdictional question presented by the Commission's order may be more correctly stated, it is believed, as follows:

Does the Federal Power Commission have jurisdiction under Section 7(c) of the Natural Gas Act to require that Humble obtain a certificate of public convenience and necessity before it can acquire, through the device of acquiring the common capital stock of the corporation owning such facilities, the facilities with which Transmission engages in the transportation and sale of natural gas subject to the jurisdiction of this Commission?

In its brief the Respondent appeared to recognize the implications inherent in the language above set out but made no attempt to argue the point as so stated.

It is quite clear that upon the acquisition of all of the stock of Transmission, Humble will have complete control of that corporation, will in effect select the management as it sees fit and will control and manage the company as a wholly owned subsidiary of Humble. The officers and the management of the acquired corporation will be appointed and elected by the acquiring corporation. Thus, Humble will have as complete control of Transmission's facilities indirectly through the ownership of the latter's stock as it would have were it purchasing the facilities directly.

That that which lawfully cannot be done directly should not be allowed to be done indirectly is a generally accepted regulatory policy, and certainly no fault can be found with it. Undoubtedly the acquisition of all of the stock of a corporation results in the acquisition of all of the assets of that corporation and, therefore, the acquisition of all of such stock affords a means by which there may be achieved indirectly that which Section 7(c) states may not be done directly without authorization. It does not necessarily follow, however, that Congress intended the words "acquire any such facilities" to mean the acquisition thereof by the "device" of the acquisition of all of or the controlling stock in the corporation. It is not believed that it was so intended.

In drafting Section 7(c) Congress could not have been unaware that a natural-gas company's facilities could be acquired by the acquisition of the stock of the corporation. Staff counsel contends that no method of acquisition of facilities was specified for the simple reason that the statute intended to grant the Commission jurisdiction over all acquisition of facilities regardles of how achieved. It is the opinion of this examiner, however, that the converse is true. Had Congress so intended it could have made this quite clear simply by the insertion of the words "directly or indirectly" after the word "acquire." To attribute to Congress in the drafting of this legislation such ineptitude and unawareness of the meaning of words is unrealistic and illogical. The fact that Congress did not include the words "directly or indirectly" is pursuasive that it did *not* so intend. It is not the function of an administrative agency to rewrite the laws which it is charge with enforcing. This is the function of Congress. (*Cf. Atlanta Trading Corporation* v. *Federal Trade Commission*, 258 F. 2d 365, 374)

Although it too has been fully aware of this indirect method of acquiring facilities during the 23 years which have passed since the passage of the Natural Gas Act, the Commission has not up to now sought to assert control over acquisition of stock although there have been numerous occasions when the opportunity to do so has presented itself.

Nor has there been cited a single court decision which supports a different view. On the contrary, the decisions of the courts bearing upon the subject clearly distinguish between the acquisition of stock as such and the acquisition of facilities as such. In his brief Staff counsel quotes from the decision of the Court of Appeals in *People of the State of California* v. *Federal Power Commission* (*supra*). That case involved an acquisition of substantially all of the stock, but it also involved an application for authorization for the merger of facilities.

The reasonableness of the view that Congress did not intend the meaning Staff counsel attributes to Section 7(c) can be demonstrated, it is believed, by simply asking the rhetorical question, at what point in percentage of stock acquired does the acquisition of the stock of a corporation become the acquisition of "the facilities" of the corporation.

Under the Staff's theory would a certificate be required only in those instances in which all of the stock of the corporation is to be purchased by a person, group of persons or a corporation in a single transaction? Or going to the other extreme, would such authorization be required for the purchase of a single share of stock? A sufficient number of purchases of single shares could conceivably, and would ultimately, result in complete control of a corporation. Would authorization be required only when the accumulation of shares develop to the point of control? And, by what criteria would that point be determined? Obviouly, control may be achieved at a different point and under different circumstances and at different times with different corporations.

Staff counsel contends that unless authorization is required for the acquisition of facilities by the device of stock purchase "a company could acquire jurisdictional facilities without surveillance by the Commision." It is certainly true that under the concept here adopted, persons, firms or corporations acquiring facilities subject to the Commission's jurisdiction are not themselves, as individuals or as a corporation, subject to the "surveillance" of this Commission. To make them so would indeed create an anomalous situation. But the corporation owning and operating such facilities and the facilities themselves would be subject to the control and regulation of this Commission both before and after such acquisition. Nor can that jurisdiction be evaded by the abandonment of such facilities without the authorization of this Commission. This is acknowledged by Staff counsel in the quotation set out above (*Supra*, P. 1087). It is not at all clear, then, what the nature of the surveillance is which Staff counsel contends may be evaded by the "device" here under consideration.

Upon the briefs filed and the arguments therein presented it is found and concluded that Humble has made the showing required by Paragraph (A) of the Commission's order of December 13, 1961, and that Section 7(c) of the Natural Gas Act does not require the authorization of this Commission for the acquisition by Humble of Transmission's stock as proposed herein.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal, or upon its own motion as provided in the Commission's Rules of Practice and Procedure, that:

The proceedings herein be and the same are herewith terminated.

EDWARD B. MARSH,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

MAGNA OIL CORPORATION (SUCCESSOR TO THE GRANDE CORPORATION DOCKET NO. G–16072

ORDER GRANTING EXTENSION OF TIME

(Issued June 1, 1962)

By its order issued March 5, 1962, in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, 27 FPC 441, the Commission disposed of more than 400 proceedings including that above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. With respect to the instant docket, ordering paragraph (A) of the March 5 order directed Magna Oil Corporation (Magna) to refund tax-reimbursement amounts collected from its direct customer Texas Gas Transmission Corporation (Texas Gas). Ordering paragraph (C) of the March 5 order directed that within 90 days from the date of issuance thereof, Magna's predecessor report to the Commission the details of its refund calculations and submit copies of releases from Texac Gas as to the required refunds. By order issued April 26, 1962 in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, 27 FPC 847, the Commission denied applications for rehearing of the March 5 order in the above, as well as other, dockets. On May 24, 1962 Magna filed a motion seeking to stay the effectiveness of the March 5 order, insofar as applicable to the above docket, until 30 days after conclusion of judicial review of said order in that docket. The motion recites that Magna intends to seek judicial review of the March 5 order and that failure of the Commission to grant the stay pending such review would cause it irreparable injury.

For reasons stated in our order of April 13, 1962 granting Pan American Petroleum Corporation an extension of time for compliance,[1] we are disposed to extend the time within which Magna must comply with ordering paragraphs (A) and (C) of the Commission's March 5 order, for a period ending 30 days after conclusion of judicial review of that order in the instant docket.[2] The extension is conditional, however, upon the payment by Magna to Texas Gas of interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the order of March 5.

The Commission finds:

(1) There is good cause for extending the time within which Magna must comply with the requirements of ordering paragraphs (A) and (C) of our order of March 5, 1962, for a period ending 30 days after conclusion of judicial review of that order in the instant docket.

(2) It is just and reasonable and in the public interest that Magna be required to pay Texas Gas interest, at a rate of 7% upon the amounts to be refunded, for the period commencing on the 91st day after issuance of the March 5 order.

The Commission orders:

(A) The time within which Magna must comply with ordering paragraphs (A) and (C) of the Commission's order of March 5, 1962 is extended for a

[1] Pan American Petroleum Corporation, Docket No. G–15641: Pan American Petroleum Corporation (Operator), *et al.*, Docket Nos. G–15650 and G–15780, 27 FPC 686.

[2] It should be understood that the 30th day after judicial review in the instant docket is the date upon which Magna must comply with the March 5 order; it is *not* the date upon which the 90 day period referred to in ordering paragraph (C) commences to run.

period ending 30 days after the conclusion of judicial review of the Commission's order.

(B) Magna shall pay Texas Gas interest, at a rate of 7% upon the amounts required to be refundsd, for the period commencing on the 91st day after issuance of the March 5, 1962 order.

(C) The time within which Texas Gas must comply with ordering paragraphs (B) and (D) of the March 5, 1962 order, insofar as applicable to the instant docket, is extended for a period ending 60 days after conclusion of judicial review of that order in said docket.

(D) If Magna shall not have filed petitions for review of the March 5 order in the instant docket within the 60 day period prescribed by statute, the extension of time herein granted shall be deemed inoperative and of no effect.

MONTANA-DAKOTA UTILITIES CO., DOCKET NOS. CP61-234, CP61-297; AMERADA PETROLEUM CORP., CI61-1133; SIGNAL OIL & GAS CO., CI61-1271; LYDA HUNT-HERBERT TRUSTS, ET AL., CI61-1621; TEXACO INC.,[1] CI61-1687; CONTINENTAL OIL CO., ET AL., G-14440

ORDER GRANTING MOTIONS FOR EARLY ADOPTION OF EXAMINER'S DECISION AND FOR SUBSTITUTION OF PARTY

(Issued June 1, 1962)*

Syllabus

1. While few gas prices are available for comparison in area here involved, such prices, together with record, sufficiently support 16-cent price proposed by Hunt-Herbert and TXL [now Texaco, Inc.]. P. 1101.
2. Applications of Amerada and Signal severed from proceeding for subsequent decision as to disputed issues of price and jurisdiction. P. 1104.
3. Commission *issues* certificates of public convenience and necessity to Montana-Dakota and producer applicants under Section 7 of the Natural Gas Act. Pp. 1093; 1103.

Earl H. A. Isensee and *Armin Johnson* for Montana-Dakota Utilities Co.

William R. Allen and *Cecil E. Munn* for Signal Oil & Gas Co.

N. Kenneth Scott, Jr., *Cecil E. Munn* and *Joseph W. Morris* for Amerada Petroleum Corp.

Robert W. Henderson and *Robert Kennedy* for Lyda Hunt-Herbert Trusts, et al.

George B. Mickum, III, *Richard B. Taylor* and *James R. Townsend* for TXL Oil Corp.

Martin Vaaler, *Bruce Hagen* and *Wallace Owen* for North Dakota Public Service Commission.

Richard C. Steffey for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

On May 21, 1962, Texaco Inc. (Texaco) filed a motion in the above-entitled consolidated proceeding requesting that the Commission adopt as its final decision at the earliest possible date the examiner's decision, issued May 16, 1962, which granted certificates of public convenience and necessity to all appli-

[1] Successor to the TXL Oil Corporation.

* Initial decision appears on P. 1094.

cants except Amerada Petroleum Corporation (Amerada) and Signal Oil and Gas Company (Signal) whose applications were severed by the examiner from the consolidated proceeding for a subsequent decision regarding two contested issues which are described on page 1094 of the examiner's decision and which involve only the applications of Amerada and Signal.*

Texaco states as grounds for its motion (1) that immediate action by the Commission will enable Montana-Dakota Utilities Co. (MDU) to reduce the amount of gas which is being flared at the present time to the extent that MDU's existing facilities have capacity to take gas from the Lignite gasoline plant of Texaco and the North Tioga gasoline plant of Lyda Hunt-Herbert Trusts, *et al.* (Hunt-Herbert) and (2) that the relatively short construction season which prevails in North Dakota makes it essential that MDU receive prompt authorization in order that all requisite facilities may be constructed in time to provide the additional service proposed in MDU's applications by the 1962-63 heating season.

Hunt-Herbert, MDU, and the North Dakota Public Service Commission have filed telegrams in support of Texaco's motion for early adoption of the examiner's decision. Under Section 1.12(c) of the Commission's Rules of Practice and Procedure, any party or staff counsel has ten days within which to answer or object to a motion filed with the Commission. Since the ten-day period within which answers or objectives to Texaco's motion has expired without objection or answer having been filed by any party or staff counsel, it appears that no party to the consolidated proceeding objects to the early adoption by the Commission of the examiner's decision prior to the expiration of the twenty-day period allowed for the filing of exceptions to examiner's decisions as provided for in Section 1.31 of the Commission's Rules of Practice and Procedure.

On April 27, 1962, Texaco also filed motions requesting that it be substituted for The TXL Oil Corporation as the party in interest in Docket No. CI61–1687 and as the applicant in the application filed by The TXL Oil Corporation in Docket No. CI61–1687. Texaco's motions are accompanied by copies of a general indenture and conveyance, assignment and transfer, executed by TXL and Texaco on April 12, 1962. Texaco's motion to substitute party also states that "Effective April 19, 1962, TXL transferred and conveyed to Texaco all of its assets, properties and rights, and Texaco assumed all of the liabilities of TXL".

The Commission finds:

It is appropriate and necessary in carrying out the provisions of the Natural Gas Act that Texaco's motions for substitution of party and for early adoption of the examiner's decision issued herein be granted.

The Commission orders:

(A) Texaco's motions to substitute party and amend the application in Docket No. CI61–1687 are hereby granted so as to substitute Texaco Inc. for The TXL Oil Corporation as the applicant in the application filed in Docket No. CI61–1687 and as the party in interest in the proceeding in Docket No. CI61–1687.

(B) Texaco's motion for early adoption of the examiner's decision issued May 16, 1962, in this consolidated proceeding is hereby granted, and such decision as to the non-contested aspects of the consolidated proceeding is hereby adopted as the final decision of the Commission herein.

* Order issued August 28, 1962, severing price issue and issuing certificates to Amerada and Signal, 28 FPC 367.

DECISION ON THE FIRST ISSUES

UPON APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY IN NONCONTESTED DOCKETS

(Issued May 16, 1962)

WESTON, *Presiding Examiner:* In this proceeding, Staff Counsel has presented by appendix to the Staff brief the proposed decision and order disposing of two uncontested dockets. There have been no suggestions concerning, or objections to, the Staff proposal. Work on the facilities involved in the uncontested dockets must be completed during the current 1962 summer season, which, of course, is relatively short in the North Dakota construction area. Therefore, the decision thereon should be expedited. The form and substance of the proposed decision and order as drafted by Staff Counsel is entirely satisfactory, and is adopted in the following text as the decision of the Presiding Examiner.

In this consolidated certificate proceeding, all of the above-named producers, except Continental Oil Company (Continental),[1] seek certificates of public convenience and necessity, pursuant to Section 7(c) of the Natural Gas Act, authorizing them to sell residue gas produced from the Nesson Anticline in northwestern North Dakota to Montana-Dakota Utilities Co. (MDU) at a price of 16 cents per Mcf in the applications of Lyda Hunt-Herbert Trusts *et al.* (Hunt-Herbert) and the TXL Oil Corporation (TXL)[2] and 17 cents per Mcf in the applications of Amerada Petroleum Corporation (Amerada) and Signal Oil and Gas Company (Signal). All gas to be sold to MDU by Hunt-Herbert, TXL, Amerada, and Signal will be delivered to MDU from the tailgates of three gasoline plants which will process casinghead gas resulting from the production of oil except that Amerada is obligated to produce some nonassociated gas from deep reservoirs when called upon to do so by MDU. This nonassociated gas will also be processed in a gasoline plant prior to delivery to MDU.

In its two interrelated applications, MDU requests certificates of public convenience and necessity authorizing it to construct and operate the pipeline facilities, at an estimated cost of $5,353,480,[3] necessary to transport and deliver the additional volumes of gas, to be acquired from the producers, to both its existing and proposed new customers, and to integrate an extant intrastate pipeline[4] with its interstate gas transmission system.

A hearing was held on January 22, 24, 25, and 26, 1962, and February 26, 1962, during which MDU presented two witnesses, the producers presented 13 witnesses, and the Staff presented one witness. At the conclusion of the hearing, the Staff and the applicants entered into a joint statement in which it was agreed that the only disputed issues raised by the applications were: (1) whether certain sales which Amerada and Signal propose to make are jurisdic-

[1] Continental filed an application to amend a certificate previously issued to it in Docket No. G–14440 under which Continental is authorized to sell to MDU gas produced from leases in Park County, Wyoming. Continental's gas, under an amendment to its FPC Gas Rate Schedule No. 156, is intended to be sold at a price of 10 cents per Mcf at a pressure base of 15.025 pounds per square inch absolute.

[2] Texaco, Inc. has succeeded to TXL as of April 19, 1962, and a motion to substitute parties pends before the Commission.

[3] Of this estimated total cost, an amount of $455,700 in Docket No. CP61–234 and an amount of $178,380 in Docket No. CP61–297 are related to the construction of distribution systems in several communities and are consequently nonjurisdictional facilities.

[4] MDU's application gives the value of the intrastate pipeline and the branch lines, city-gate stations and distribution systems related to the intrastate sysem at $5,152,846.92 as of December 31, 1960.

tional under the Commission's Opinion No. 348, issued October 23, 1961, in *Lo-Vaca Gathering Company, et al.*, Docket Nos. C161–693, *et al.*, 26 F.P.C. 606, as claimed by the Staff, or nonjurisdictional under *State of North Dakota* v. *F.P.C.*, 247 F. 2d 173 (CA8), as claimed by Amerada and Signal, and (2) whether *all* producers, including Amerada and Signal, should be allowed a price of 16 16 cents per Mcf for their gas, as advocated by the Staff, or whether a price differential should be permitted allowing Amerada and Signal to charge 17 cents per Mcf for their gas and TXL and Hunt-Herbert 16 cents per Mcf for their gas, as advocated by Amerada and Signal.

When it became obvious that the only contested issues in this consolidated proceeding involved the applications of Amerada and Signal, counsel for the other applicants requested that the Examiner issue an early decision as to the noncontested applications. As grounds for this request, they stated that a final decision as to the noncontested applications would permit MDU to get its facilities constructed during the relatively short construction season prevailing in North Dakota and would reduce to a minimum the amount of gas which would otherwise have to be flared if decision on all of the applications were to be delayed until the Commission has reviewed and decided the contested issues regarding Amerada's and Signal's applications. This procedure is supported by the Staff and unopposed by any party to the proceeding. Therefore, this decision will sever Amerada's and Signal's applications from this consolidated proceeding and will issue certificates to all other applicants, subject to such terms and conditions as may be required by the public convenience and necessity and subject to the Commission's approval of this procedure.

MDU's application, filed March 7, 1961, in Docket No. CP61–234, as supplemented May 23, 1961, June 26, 1961, August 24, 1961, September 28, 1961, and December 15, 1961, proposes to integrate with its existing interstate system an 80-mile, 12-inch intrastate line which extends from Tioga, North Dakota, to Minot, North Dakota. The intrastate line would be interconnected with the existing system at the terminal point of one of MDU's existing main lines which extends from eastern Montana to Tioga, North Dakota. MDU also proposes to construct and operate a 106-mile, 12-inch line from Minot to Bismarck, North Dakota, the terminal point of another of MDU's main lines extending from eastern Montana into North Dakota. After MDU has interconnected the aforesaid 12-inch lines, its NorthDakota system will be integrated with its facilities in Montana to form a continuous pipeline encompassing a large area in western North Dakota.

At various points along the aforementioned 106-mile interconnecting line, MDU proposes to extend five 2-inch branch lines, having a total length of about 19.5 miles, in order to initiate retail natural-gas service to the Minot Radar Base near Minot and to the four communities of Max, Turtle Lake, Washburn, and Wilton, North Dakota. Additionally, two 3-inch branch lines, totaling approximately 22 miles in length, are proposed to be extended from the 106-mile interconnection to provide service in the communities of Garrison and Underwood, North Dakota. In conjunction with serving natural gas in these communities and the radar base, MDU proposes to construct and operate the necessary city-gate stations and the required measuring and regulating station at the terminus of the 106-mile interconnecting line near Bismarck. The estimated third-year maximum daily requirements of all six communities and the radar base[5] total 2,640 Mcf and the estimated annual requirements are 308,590 Mcf.

[5] On September 14, 1961, the North Dakota Public Service Commission issued an order in Case No. 6082 granting MDU a certificate to construct and operate distribution systems in Max, Garrison, Turtle Lake, Underwood, Washburn, and Wilton and to serve the Minot Radar Base.

MDU's application in Docket No. CP61–297, filed May 23, 1961, as supplemented June 29, 1961, and October 2, 1961, seeks authorization to construct the facilities necessary to initiate natural-gas service to three North Dakota communities and to one new industrial customer in Montana. The North Dakota communities of Watford City, Arnegard, and Alexander are proposed to be served by the construction of a lateral, composed of 11.7 miles of 6-inch pipe and 17 miles of 4-inch pipe, in a southeasterly direction from one of MDU's main lines extending from Cabin Creek, Montana, to Tioga, North Dakota. The 4-inch portion of this lateral will terminate at the city-gate station to be constructed for delivering gas to Watford City, Two branch lines, each about one mile in length and two inches in diameter, will be constructed from the Watford City lateral, together with the necessary city-gate stations, to initiate natural-gas service in Alexander and Arnegard. The third-year maximum daily requirements of these three communities are estimated to be 980 Mcf and the annual requirements are estimated at 114,390 Mcf.[6]

The new industrial customer MDU proposes to serve in Docket No. CP61–297 is the Holly Sugar Corporation, whose plant is located near Hardin, Montana. MDU will serve Holly Sugar's plant by constructing 1.6 miles of 4-inch lateral in a northwesterly direction from one of MDU's main lines which extends southwestward from the Cabin Creek Compressor Station through Montana to Worland, Wyoming. Gas will be used by Holly Sugar in the sugar beet pulp dryer which is being installed in its plant. The maximum daily requirements of the dryer are estimated at 2,000 Mcf and it is contemplated that the annual requirements will not exceed 122,000 Mcf because the dryer will be operated only about 100 days each year, beginning in October of each year.

MDU's application in Docket No. CP61–297 also proposes the installation of a 298-horsepower compressor unit[7] and rearrangement of existing facilities in its extant South Elk Basin Compressor Station in Park County, Wyoming, so as to receive additional solution gas from Continental. The solution gas will be purchased under an amendment dated March 1, 1961, of MDU's contract with Continental pursuant to which MDU presently purchases solution gas produced from the Frontier and Middle Frontier formations. The amendatory agreement covers the purchase of solution gas to become available from the Torchlight formation which occurs at a depth of 5626 to 5648 feet above the Mid-Frontier formation in Continental's Well No. 31.

Continental expects to offer MDU about 4,500 Mcf of solution gas per day. Since the present capacity of the South Elk Basin facilities is only 3,200 Mcf per day, about 1,300 Mcf of solution gas would have to be flared if the additional compression were not installed. The 298 horsepower of compressor facilities which MDU proposes to add will increase the capacity of the South Elk Basin Station to about 6,000 Mcf per day and will enable MDU to compress non-associated gas which Continental will produce from the Cloverly-Morrison formation and continue to sell to MDU under a contract with the latter dated January 1, 1960. This contract has been designated Continental's FPC Gas Rate Schedule No. 200 and supersedes Continental's FPC Gas Rate Schedule

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[6] On November 13, 1961, the North Dakota Commission issued an order in Case No. 6117 granting MDU a certificate to construct and operate distribution systems in Watford City, Alexander, and Arnegard.

[7] On November 13, 1961, MDU reported that it had completed this 298-horsepower unit and placed it in service on November 1, 1961, pursuant to temporary authority granted October 6, 1961.

No. 2, a prior 10-year contract dated January 23, 1951,[8] covering sales of gas to MDU from the Cloverly-Morrison formation.

The additional gas which MDU proposes to acquire in Docket No. CP61–297, pursuant to its gas purchase contracts with Hunt-Herbert and TXL, will be obtained from two gasoline plants which are located northeast of Tioga, a North Dakota community presently served by MDU's existing intrastate system. Hunt-Herbert's North Tioga plant is located about 13½ miles northeast of Tioga and TXL's Lignite plant is situated approximately 25 miles northeast of Hunt-Herbert's plant. MDU proposes to receive deliveries of gas from the tailgate of Hunt-Herbert's plant by constructing 13.6 miles of 8-inch transmission line[9] from the site of the plant to a point on MDU's existing pipeline near Tioga. MDU will not have to construct any facilities in addition to the aforesaid 13.6-mile line in order to receive residue gas from TXL's plant because the latter's application states that TXL will[9] construct about 24 miles of 8-inch line southwestward from its Lignite plant in order to deliver its gas into MDU's 13.6-mile line which terminates near Hunt-Herbert's North Tioga plant.

The fields which will supply the raw gas to be processed in TXL's Lignite plant are the Portal, Rival, Lignite, Flaxton, Woburn, Black Slough, Foothills, N. E. Foothills, and Rennie Lake fields, which are located in Burke County, North Dakota. MDU's application shows that the residue gas committed to MDU under the TXL contract is estimated to be 49,691 MMcf. Hunt-Herbert will obtain raw gas from producers in the North Tioga and McGregor fields in Burke, Williams, and Divide Counties, North Dakota, for processing in its North Tioga plant. The residue gas available to MDU under the Hunt-Herbert contract is estimated to be 28,443 MMcf, making a total volume of 78,134 MMcf available to MDU under both TXL's and Hunt-Herbert's contracts, as of January 1, 1961, at a pressure base of 14.73 pounds per square inch absolute.

Under Article 3 of MDU's contract with Hunt-Herbert, MDU is obligated to take, or pay for, the entire output of surplus residue gas from Hunt-Herbert's plant. If the volume of residue gas offered by Hunt-Herbert should exceed 5,000 Mcf per day for a period of 90 days, MDU is entitled to a reasonable time within which to install additional facilities to permit it to take gas in excess of 5,000 Mcf per day. MDU's estimated purchases from the North Tioga plant for the first five years of operation are based on estimates made by the Ralph E. Davis Associates and are given in the following tabulation:

MDU's estimated purchases from Hunt-Herbert

Year of estimate	Annual purchases (Mcf)	Average daily purchases (Mcf)
1962	1,715,500	4,700
1963	1,825,000	5,000
1964	2,080,500	5,700
1965	2,190,000	6,000
1966	2,591,500	7,100

Article 3 of MDU's contract with TXL provides for MDU to take, or pay for, the entire output of surplus residue gas from TXL's Lignite plant. If the volume of residue gas offered by TXL should exceed 10,000 Mcf per day for

[8] Continental was authorized February 6, 1956, to sell gas produced from the Cloverly-Morrison formation in *Continental Oil Co. et al.*, Docket Nos. G–6590 *et al.*, 15 FPC 641, affirmed *Continental Oil Company* v. *F.P.C.*, 247 F. 2d 904 (CA5).

[9] On March 1, 1962, MDU reported that construction of this 13.6-mile line had been completed on November 30, 1961, pursuant to temporary authority granted November 1, 1961. TXL also received a temporary certificate to sell gas to MDU on November 1, 1961.

a period of 90 days, MDU is entitled to a reasonable time within which to install additional facilities to permit it to take gas in excess of 10,000 Mcf per day. MDU's estimated purchases from the Lignite plant for the first five years of operation are given in the following tabulation:

MDU's estimated purchases from TXL

Year of estimate	Annual purchases (Mcf)	Average daily purchases (Mcf)
1962	2,591,500	7,100
1963	2,774,000	7,600
1964	3,139,000	8,600
1965	3,285,000	9,000
1966	3,869,000	10,600

TXL's introductory witness stated that 30 additional wells had been drilled in the Lignite area since the time of the Davis reserve studies which served as the basis for the foregoing MDU estimates. This witnss expected the Lignite plant to be producing average daily quantities of residue gas in the amount of 9,153 Mcf in the first year of operation, 12,800 Mcf by the second year, 13,300 Mcf by the third year, and 13,500 Mcf thereafter. The contracts of the producers supplying the Lignite plant have a 15-year term and the contracts supplying the Hunt-Herbert plant have a 20-year term. Neither the TXL witness nor the Davis reports placed the combined deliverability of gas from these two plants at less than 10,000 Mcf per day until after ten years of production.

The foregoing facts indicate that MDU has enhanced its system gas supply by contracting for the purchase of the surplus residue gas to become available from the North Tioga and Lignite plants. The third-year peak daily requirements of all the new service MDU is proposing in both Docket Nos. CP61–234 and CP61–297 amount to 5,620 Mcf and the annual requirements total 544,980 Mcf. As compared with this new service, MDU is proposing to attach a gas supply capable of delivering from about 17,000 Mcf to 20,000 Mcf per day and an annual volume ranging from approximately 6,500,000 Mcf to over 7,500,000 Mcf. These figures indicate that the additional gas to be acquired from Hunt-Herbert and TXL will be sufficient to meet the requirements of the proposed new customers and augment the gas supply available to MDU for maintaining consistent service to its existing customers.

As hereinbefore indicated, MDU proposes in Docket No. CP61–234 to construct and operate a new 106-mile, 12-inch pipeline between Minot and Bismarck. While some new service is proposed to be rendered by means of this interconnecting line, its primary purpose is to enable MDU to increase its capacity sufficiently to enable it to take the full output of residue gas from the gasoline plants. MDU originally proposed to construct this line in order to take additional volumes of gas from Amerada's and Signal's Tioga plant, but MDU's policy witness stated during the hearing that regardless of whether Amerada, Signal, Hunt-Herbert, and TXL were *all* authorized to make sales to MDU, or whether Hunt-Herbert and TXL *only* were authorized to make sales to MDU, there would not be, under either of the foregoing assumptions, sufficient capacity in MDU's system, without construction of the 106-mile line, to take the entire output of gas from the gasoline plants as required under the gas purchase contracts.

Since acquirement of the Hunt-Herbert and TXL gas will generally improve MDU's system gas supply, it appears to be in the public interest for MDU

to be authorized at this time to construct all of the facilities, including the 106-mile interconnecting pipeline, requested by MDU in both Docket Nos. CP61–234 and CP61–297 despite the fact that decision regarding the sale of gas to MDU by Amerada and Signal will have to be deferred for subsequent decision pending further consideration of the two issues regarding price and jurisdiction which have been raised solely as to Amerada's and Signal's applications.

MDU's application indicates that about 90 days will be required for MDU to construct the 106-mile interconnecting line and place it into operation. This means that MDU's capacity during the summer of 1962 will be just as limited as it was shown to be in MDU's request for temporary authority which was filed on October 2, 1961, in Docket No. CP61–297. On pages 39–41 of its brief the Staff points out that MDU's ability to take gas from the North Tioga and Lignite plants will be considerably limited in the summer months, prior to the construction of the 106-mile line, because MDU has very little demand for gas in North Dakota in the warm months and consequently has to transport most of the gas delivered to it from North Dakota gasoline plants into Montana for injection into storage fields. MDU is presently taking about 30,000 Mcf of residue gas per day from Amerada's and Signal's Tioga plant under contracts in effect prior to this proceeding. Consequently, MDU's ability to take additional gas with existing capacity is apparently limited to as little as 1,300 Mcf per day during the month of July.

The lowest estimate given for the volume of residue gas which will be available for delivery to MDU from both the North Tioga and Lignite plants when they begin initial operations is 10,000 Mcf per day. There can be no doubt, therefore, but that the volumes of gas which will be produced by Hunt-Herbert and TXL will be in excess of MDU's pipeline capacity until such time as the 106-mile line has been completed. Because of MDU's inability to take the entire output of the residue gas from TXL's plant, MDU and TXL entered into an agreement dated August 31, 1961, amending TXL's basic gas sales contract so as to remove MDU's obligation to take, or pay for, the entire output of the Lignite plant during the months of March through October, inclusive.

When MDU and TXL filed their requests for temporary authority, MDU stated that it proposed to take gas *proportionately* from Hunt-Herbert's and TXL's plants *if* both Hunt-Herbert and TXL were given temporary certificates. However, MDU made this assumption as to proportionate takes of gas from the two plants on the premise that Hunt-Herbert would amend its contract, in the same manner as TXL did, to remove MDU's obligation to take the entire output of the Hunt-Herbert plant during the months of March through October, inclusive.

Inasmuch as Hunt-Herbert has never amended its contract with MDU so as to remove MDU's obligation to take the entire output of residue gas from the North Tioga plant, the staff proposes that a condition be attached to the certificate issued to Hunt-Herbert and TXL so as to provide for proportionate takes from Hunt-Herbert's and TXL's plants during the period between the issuance of the permanent certificates and the time MDU is able to complete its 106-mile line and place it into operation. It has been shown, of course, that once MDU has started operating this proposed 106-mile line that it will be able to take the entire output of all the gasoline plants. Such a condition appears to be required by the public convenience and necessity to protect MDU from having to pay for gas it can't take prior to the completion of its facilities and to provide for equitable takes of gas it can't take prior to the completion of its facilities and to provide for equitable takes of gas from both Hunt-Herbert's North Tioga plant and TXL's Lignite plant.

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By way of summary and in order to state the facts specifically, the total facilities which MDU proposes to construct in both Docket Nos. CP61–234 and CP61–297 are given in the tabulation below, together with the estimated costs, including allowance for contingencies and interest during construction:

Proposed facilities	*Estimated cost*
106-Mile, 12-Inch Interconnecting Line	$3,400,000
Branch Lines to Serve Six Communities and Radar Base and Bismarck Regulation Station	359,070
City-Gate Stations for Six Communities and Radar Base	73,610
Distribution Systems in Six Communities of Max, Turtle Lake, Washburn, Wilton, Garrison, and Underwood, North Dakota	455,700
Total Cost for All Proposals in Docket No. CP61–234	4,288,380
13.6-Mile, 8-Inch Extension to North Tioga Plant to Receive Gas from Hunt-Herbert and TXL plus Metering and Regulating Stations	319,480
Installation of 298-Horsepower Compressor Unit and Rearrangement of Facilities in South Elk Basin Compressor Station	71,060
Lateral Line to Serve Watford City and Branch Lines to Serve Alexander and Arnegard	438,560
City-Gate Stations to Serve Alexander, Arnegard, and Watford City	25,480
Distribution Systems in Alexander, Arnegard, and Watford City	178,380
Lateral Line and Metering and Regulating Station to Serve Holly Sugar Corporation	32,140
Total Cost for All Proposals in Docket No. CP61–297	1,065,100
Total Estimated Costs in Both Dockets	5,353,480

There appears to be no questions as to MDU's ability to finance the projects proposed in both Docket Nos. CP61–234 and CP61–297. MDU expects to finance its projects by the issuance of preferred stocks and from short-term bank loans and working capital.

Even though this is a preliminary decision to be issued prior to a determination as to the real price issue in this proceeding, some consideration should be given to the initial rates which Hunt-Herbert and TXL propose to charge. Scrutiny is required under *Atlantic Refining Co.* v. *Public Service Commission*, 360 U.S. 378, and a review of the initial rates is especially important in view of the fact that no initial price is given for the North Dakota area in the Commission's *Statement of General Policy No. 61–1*, issued September 28, 1960, 24 FPC 818, 18 CFR 2.56. Of course, any discussion of initial prices in this preliminary decision must be limited to matters which will not be prejudicial to the positions taken by Amerada and Signal in connection with the price and jurisdictional issues involved in their applications which are being severed for separate decision.

Prior to the filing of the applications in this proceeding, MDU was purchasing gas from Amerada and Signal under four contracts executed in 1955. Two of these contracts provide for intrastate sales at an initial price of 16 cents per Mcf with one-cent price escalation provisions every five years, the first escalation having gone into effect on January 1, 1961. The other two contracts provide for interstate sales on a "dump" basis, in that Amerada and Signal offer residue gas under the "dump" contracts only when such gas would otherwise have to be flared. The "dump" contracts provide for an initial price of 9 cents per Mcf at the same pressure base used in the firm con-

tracts, that is, 14.73 pounds per square inch absolute. The "dump" contracts have no price escalation provisions and have an indefinite term.

In this proceeding Amerada and Signal propose to sell gas to MDU under two intrastate contracts and two interstate contracts which would displace the aforementioned intrastate and "dump" contracts under which gas is presently being sold to MDU.[10] These four contracts provide for an initial price of 17 cents per Mcf at a pressure base of 14.73 pounds, with one-cent escalation provisions each five years thereafter for the 20-year terms of the contracts.

Hunt-Herbert's and TXL's contracts have already been discussed fairly extensively. They provide for interstate sales at a proposed initial price of 16 cents per Mcf at a pressure base of 14.73 pounds, with one-cent escalation provisions each five years thereafter for their 20-year terms.

Amerada's and Signal's witnesses have testified that the "dump" contracts were negotiated with MDU in order to prevent the flaring of gas and to sell gas at whatever price could be obtained. These "dump" contracts are not considered firm in that they fail to provide for the sale of specific quantities of gas or for the commitment of any reserves to MDU.

The foregoing discussion shows that in the North Dakota area the only prices which can be compared in this proceeding are 16 cents and 17 cents. Each of these prices relates to pipeline quality gas delivered to MDU at high pressure from the tailgates of gasoline plants. All "pipeline quality" gas delivered to MDU under any of the contracts must contain no more than one-fourth grain of hydrogen sulphide or more than twenty grains of total sulphur per 100 cubic feet or more than one pound of water per million cubic feet. The Btu content can be no less than 988 Btu. Because gas with a higher Btu content than 1040 per cubic foot is not compatible for mixing with other gas in MDU's system for use in the appliances of MDU's customers, each of the contracts provides for the seller to inject air into the residue gas to ensure that the Btu content does not exceed 1040 Btu's per cubic foot.

From the foregoing discussion, it can be seen that few gas prices are available for comparison in the area involved in this proceeding. Such prices, however, together with the record herein, sufficiently support the price at which Hunt-Herbert and TXL propose to sell their gas. Further discussion of the prices involved in this proceeding will be deferred for consideration in the subsequent decision concerning Amerada's and Signal's applications.

Formal Findings

(1) Montana-Dakota Utilities Co., a Delaware corporation, having its principal place of business at Minneapolis, Minnesota, is engaged in the transportation of natural gas in interstate commerce, and the sale in interstate commerce of natural gas for resale for ultimate public consumption, and therefore is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order in Docket Nos. G–220 and G–402, 5 FPC 64.

(2) Lyda Hunt-Herbert Trusts *et al.*, a group of trusts created under the laws of Texas, with principal office at Dallas, Texas, and The TXL Oil Corporation, a Delaware corporation with principal place of business at Dallas, Texas, upon commencement of the service hereinafter authorized, will be engaged in the sale of natural gas in interstate commerce for resale for ultimate

[10] Even if their applications in this proceeding are granted, Signal and Amerada have indicated that they do not contemplate filing for permission to abandon this "dump sales" service because a situation might arise in the future when they would need to resort to selling "dump gas" rather than having to flare it.

public consumption, subject to the jurisdiction of the Commission, and will therefore be "natural-gas companies" within the meaning of the Natural Gas Act.

(3) The facilities to be constructed or integrated into its interstate system by MDU, as hereinbefore described and as more fully described in the applications in Docket Nos. CP61–234 and CP61–297 as supplemented, are proposed to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of MDU's existing pipeline system and the construction, integration, and operation thereof by MDU are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) The sales of natural gas by Hunt-Herbert and TXL to MDU, as hereinbefore described and as more fully described in the applications in Docket Nos. CI61–1621 and CI61–1687, respectively, will be made for resale in interstate commerce, subject to the jurisdiction of the Commission, and such sales by Hunt-Herbert and TXL, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) Hunt-Herbert and TXL, respectively, are able and willing to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and to the requirements, rules, and regulations of the Commission thereunder.

(6) The construction, integration, and operation of the facilities proposed by MDU in Docket Nos. CP61–234 and CP61–297 and the sales of natural gas proposed by Hunt-Herbert and TXL in Docket Nos. CI61–1621 and CI61–1687, respectively, together with the construction and operation by Hunt-Herbert and TXL of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(7) Public convenience and necessity require that the general terms and conditions set forth in paragraphs (a), (b), (c)(4), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.20) should attach to the issuance of the certificates hereinafter granted to MDU and to the exercise of the rights granted thereunder, and that the time within which construction of the facilities authorized by this order shall be completed and placed in actual operation should be fixed at six months from the date on which this order issues.

(8) MDU's existing capacity is not sufficient to take the entire output of Hunt-Herbert's and TXL's gasoline plants pending the completion of the 106-mile interconnecting line hereinafter authorized, and consequently MDU's, Hunt-Herbert's and TXL's certificates should be conditioned to provide that MDU shall take residue gas from Hunt-Herbert's and TXL's plants to the extent that its existing pipeline capacity permits; further, pending such time as MDU is able to complete the 106-mile line and place it into operation, MDU should not be liable to pay for any gas offered to it by Hunt-Herbert or TXL above the quantity which its existing facilities are actually able to transport on any given day.

(9) Pending the time when MDU's facilities are capable of taking the full output of residue gas from both Hunt-Herbert's and TXL's plants, MDU shall take gas proportionately from both plants so that its limited capacity is equitably used to take gas from each plant.

(10) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that the certificate issued to Continental Oil Company, Operator, *et al.*, in Docket No. G–14440, be amended as hereinafter provided.

(11) In order that MDU may commence construction of its facilities as soon as possible so as to reduce the amount of gas which would otherwise have to be flared, and in order that sufficient time may be allowed for completion of construction prior to the 1962–63 heating season, it is appropriate for Amerada's and Signal's applications to be severed from this consolidated proceeding for a subsequent decision as to the two disputed issues of price and jurisdiction which have been raised regarding Amerada's and Signal's applications.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission pursuant to its Rules of Practice and Procedure, that:

(A) Certificates of public convenience and necessity be and the same are hereby issued authorizing Montana-Dakota Utilities Co. to construct, integrate, and operate the facilities hereinbefore described, all as more fully described in the applications in Docket Nos. CP61–234 and CP61–297, for the transportation and sale of natural gas in interstate commerce as therein set forth, upon the terms and conditions of this order.

(B) The general terms and conditions set forth in paragraphs (a), (b), (c)(4), and (e) of Section 157.20 of the Commission's Regulations under the Natural Gas Act shall attach to the issuance of the certificates granted in paragraph (A) above and to the exercise of the rights granted thereunder.

(C) The time within which the facilities authorized in paragraph (A) above shall be completed and placed in actual operation is hereby fixed at six months from the date on which this order issues.

(D) Certificates of public convenience and necessity be and the same are hereby issued authorizing the sales by Lyda Hunt-Herbert Trusts *et al.*, and The TXL Oil Corporation to MDU of natural gas in interstate commerce for resale, together with the construction and operation by Hunt-Herbert and TXL of any facilities subject to the jurisdiction of the Commission necessary therefor, as hereinbefore described and as more fully described in the applications in Docket Nos. CI61–1621 and CI61–1687, respectively.

(E) The certificates granted in paragraph (D) above are not transferable and shall be effective only so long as Hunt-Herbert and TXL continue the acts and operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations, and orders of the Commission thereunder.

(F) The certificates issued in paragraphs (A) and (D) above are hereby conditioned to provide that, prior to the completion of MDU's proposed 106-mile line, MDU shall take residue gas from Hunt-Herbert's and TXL's plants to the extent that its existing pipeline capacity permits; further, pending the time when MDU is able to complete the 106-mile line and place it into operation, MDU shall not be liable to pay for any gas offered to it by Hunt-Herbert or TXL above the quantity which its existing facilities are actually able to transport on any given day.

(G) The certificates issued in paragraphs (A) and (D) above are hereby further conditioned to provide that pending the time when MDU's facilities are capable of taking the full output of residue gas from both Hunt-Herbert's and TXL's plants, MDU shall take gas proportionately from both plants so that its limited capacity is equitably used to take gas from each plant.

(H) The certificate issued to Continental on July 17, 1958, in Docket No. G–14440 in *Montana-Dakota Utilities Co. et al.*, Docket Nos. G–13965 *et al.*, 20 FPC 50, is hereby amended to grant authorization for the additional sales which Continental proposes to make to MDU as hereinbefore described and as more fully described in Continental's application to amend the certificate previously issued to it in Docket No. G–14440.

(I) The grant of the certificates in paragraph (D) above shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or of Section 154 of the Commission's Regulations thereunder requiring the filing of a rate schedule for the service herein authorized, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against Hunt-Herbert or TXL. Further, our action in this proceeding shall not foreclose nor prejudice any future proceedings or objections relating to the operation of any price or related provision in the gas purchase contracts herein involved.

(J) The certificates issued to Hunt-Herbert and TXL in paragraph (D) above shall be accepted in writing and under oath within 30 days from the date of issuance of this order.

(K) Amerada's application in Docket No. CI61–1133 and Signal's application in Docket No. CI61–1271 are hereby severed from this consolidated proceeding for a subsequent decision as to the disputed issues hereinbefore described on page 1094 of this decision.

ROBERT M. WESTON,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NATURAL GAS STORAGE COMPANY OF ILLINOIS
DOCKET NO. CP62–79

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 1, 1962)

On September 27, 1961, as supplemented on October 9, and December 8, 1961, Natural Gas Storage Company of Illinois filed in Docket No. CP62–79 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of certain natural gas storage facilities at the Herscher Storage Field, Kankakee County, Illinois, all as more fully set forth in the application, as supplemented.

The additional facilities required for the proposed operation are:

(1) One additional 6,500 BHP gas turbine centrifugal compressor unit at Compressor Station No. 201;

(2) Approximately 6,200 feet of 20-inch gathering lines, of which approximately 3,400 feet will be used to replace existing 10-inch and 12-inch gathering lines that will be retired;

(3) Approximately 2,200 feet of 10-inch, 2,600 feet of 12-inch, and 1,900 feet of 30-inch gathering lines;

(4) Six injection-withdrawal Galesville Reservoir wells;

(5) One Galesville Reservoir observation well;

(6) Three Mt. Simon Reservoir observation wells; and

(7) Additional cushion gas, and miscellaneous facilities necessary or convenient to the operation of the above described facilities.

The total estimated cost of Applicant's proposed facilities is $3,360,860, which will be financed from funds on hand and from short-term loans from Natural Gas Pipeline Company of America or from banks.

The proposed facilities will be used to provide a maximum peak-hours withdrawal capacity of 40,000 Mcf and to increase the maximum daily withdrawal from storage by 75,000 Mcf to a total of 800,000 Mcf of natural gas by using all three reservoirs, namely the Galesville and Mt.Simon Reservoirs at the Herscher Field and the Cooks Mills Field. Such gas will be stored for the accounts of existing customers of Natural Gas Pipeline Company of America.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 24, 1962, respecting the matters involved in and the issues presented by the Application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omittd and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Natural Gas Storage Company of Illinois, an Illinois corporation having its principal place of business of Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its opinion and order of September 11, 1952, in Docket No. G–1757 (11 FPC 366).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, will be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof, and the increased storage service by Applicant, are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The proposed construction and operation of facilities, and the proposed increased storage service by Applicant, are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of said Regulations.

(6) The submission of reports required of Applicant by applicable orders of the Commission in dockets involving the Herscher Galesville, Herscher Mt. Simon, and Cooks Mills gas storage projects should be continued.

(7) The total combined reservoir withdrawals of natural gas from the Herscher and Cooks Mills Fields should be limited to a maximum of 40,000 Mcf per hour and 800,000 Mcf per day.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Natural Gas Storage Company of Illinois, to construct and operate the facilities hereinbefore described, all as more fully described in the application, as supplemented, in this proceeding, and to render the additional storage service as proposed, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of said Regulations.

(C) The time within which the facilities hereby authorized shall be completed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act is hereby fixed at 12 months from the date on which this order issues.

(D) The submission of reports required of Applicant by applicable orders of the Commission in dockets involving the Herscher Galesville, Herscher Mt. Simon, and Cooks Mills gas storage projects shall be continued.

(E) The total combined reservoir withdrawals of natural gas from the Herscher and Cooks Mills Fields are hereby limited to a maximum of 40,000 Mcf per hour and 800,000 Mcf per day.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TEXACO INC. (SUCCESSOR TO TEXACO SEABOARD INC.) DOCKET NOS. G–15680, G–15739

ORDER GRANTING EXTENSION OF TIME

(Issued June 1, 1962)

By its order issued March 5, 1962, in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, 27 FPC 441, the Commission disposed of more than 400 proceedings including those above listed, involving rate increases based upon the additional gathering tax of 1¢ per Mcf imposed by the State of Louisiana and later invalidated by the Louisiana courts. With respect to Docket No. G–15680, ordering paragraph (A) of the March 5 order directed Texaco Inc., successor to Texaco Seaboard Inc., (Texaco) to refund tax-reimbursement amounts collected from its direct customer Transcontinental Gas Pipe Line Corporation (Transco). Ordering paragraph (C) of the March 5 order directed that within 90 days from the date of issuance thereof, Texaco report to the Commission the details of its refund calculations and submit copies of releases from Transco as to the required refunds. With respect to Docket No. G–15739, no refunds were required of Texaco. By order issued April 26, 1962 in *Texaco Inc., et al.*, Docket Nos. G–15546, *et al.*, 27 FPC 847, the Commission denied applications for rehearing of the March 5 order in the above, as well as other, dockets. On May 28 Texaco filed a motion seeking to stay the effectiveness of the March 5 order, insofar as applicable to the above dockets, until 30 days after conclusion of judicial review of said order in those dockets. The motion recites that Texaco intends to seek judicial review of the March 5 order and that failure of the Commission to grant the stay pending such review would cause it irreparable

injury. Inasmuch as no refund obligations were imposed upon Texaco in Docket No. G–15739, we shall deem the motion for stay to be addressed solely to the Commission's order in Docket No. G–15680.

For reasons stated in our order of April 13, 1962 granting Pan American Petroleum Corporation an extension of time for compliance,[1] we are disposed to extend the time within which Texaco must comply with ordering paragraphs (A) and (C) of the Commission's March 5 order, for a period ending 30 days after conclusion of judicial review of that order in Docket No. G–15680.[2] The extension is conditional, however, upon the payment by Texaco to Transco of interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the order of March 5.

The Commission finds:

(1) There is good cause for extending the time within which Texaco must comply with the requirements of ordering paragraphs (A) and (C) of our order of March 5, 1962, for a period ending 30 days after conclusion of judicial review of that order in the instant docket.

(2) It is just and reasonable and in the public interest that Texaco be required to pay Transco interest, at a rate of 7% upon the amounts to be refunded, for the period commencing on the 91st day after issuance of the March 5 order.

The Commission orders:

(A) The time within which Texaco must comply with ordering paragraphs (A) and (C) of the Commission's order of March 5, 1962 is extended for a period ending 30 day after the conclusion of judicial review of the Commission's order.

(B) Texaco shall pay Transco interest, at a rate of 7% upon the amounts required to be refunded, for the period commencing on the 91st day after issuance of the March 5, 1962 order.

(C) The time within which Transco must comply with ordering paragraphs (B) and (D) of the March 5, 1962 order, insofar as applicable to the instant docket, is extended for a period ending 60 days after conclusion of judicial review of that order in said dockets.

(D) If Texaco shall not have filed petitions for review of the March 5 order in the instant docket within the 60 day period prescribed by statute, the extension of time herein granted shall be deemed inoperative and of no effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TEXAS EASTERN TRANSMISSION CORPORATION DOCKET NO. CP62–142

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 1, 1962)

On December 8, 1961, Texas Eastern Transmission Corporation (Applicant) filed in Docket No. CP62–142 an application pursuant to Section 7(c) of the

[1] Pan American Petroleum Corporation, Docket No. G–15641; Pan American Petroleum Corporation (Operator), *et al.*, Docket Nos. G–15650 and G–15780, 27 FPC 686.

[2] It should be understood that the 30th day after judicial review in the instant docket is the date upon which Texaco must comply with the March 5 order; it is *not* the date upon which the 90 day period referred to in ordering paragraph (C) commences to run.

Natural Gas Act for a certificate of public convenience and necessity authorizing the sale and delivery of natural gas to Texas Gas Transmission Corporation (Texas Gas) from four of Applicant's units in the Calhoun Field, Ouachita Parish, Louisiana.

The gas to be sold will be Applicant's share of the Clara Hodge, J. B. Brown No. 1, R. R. Fuller No. 1 and T. A. Grant No. 1 Units in the Calhoun Field.

The proposed sale is to be made pursuant to Applicant's FPC Gas Rate Schedule F–5, which Rate Schedule consists of a gas sales contract, dated September 3, 1958, between Texas Gas and Southwestern Gas Producing Company, Inc., and Applicant's agreement, dated November 22, 1961, ratifying the foregoing contract, to provide for the subject sale, as it basic contract in Docket No. CP62–142.

The proposed sale will be made at an initial price of 16.5 cents per Mcf at 15.025 psia plus 1.75 cents per Mcf tax reimbursement, or a total initial price of 18.25 cents per Mcf.

By letter, dated February 23, 1962, Applicant was granted temporary authorization to make the proposed sale of natural gas.

Pursuant to due notice, a public hearing was held in Washington, D. C., on May 24, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Texas Eastern Transmission Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of October 10, 1947, in Docket No. G–880 (6 FPC 148).

(2) The sale of natural gas hereinbefore described, as more fully described in the application in this proceeding, will be made in interstate commerce subject to the jurisdiction of the Commission, and such sale by Applicant, together with the contruction and operation of any facilities subject to the jurisdiction of the Commission necessity therefor, are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the services proposed and to conform to the provision of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The sale of natural gas by Applicant, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Because of the nature of the service herein proposed and hereinafter authorized, Section 154.93 of the Commission's Regulations should be applicable; accordingly, in the event that any document comprising the subject Rate Schedule F–5 was executed on or after April 3, 1961, and contains provisions, either therein or by adoption of the terms and provisions of other agreements, for a change in rate other than those permitted by said Section 154.93 of the Commission's Regulations, such rate change provisions shall be inoperative and of no effect at law and any tendered rate change under such provisions will be rejected.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued, upon the terms and conditions of this order, authorizing the sale by Applicant, Texas Eastern Transmission Corporation, of natural gas to Texas Gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary for such sale, as hereinbefore described, all as more fully described in the application in this proceeding.

(B) The certificate granted in paragraph (A) above is not transferable and shall be effective only so long as Applicant continues the operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations, and orders of the Commission.

(C) The grant of the certificate issued in paragraph (A) above shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or Part 154 or Part 157 of the Commission's Regulations thereunder, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Applicant. Further, our action in this proceeding shall not foreclose or prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contract herein involved.

(D) Because of the nature of the service herein proposed and authorized, Section 154.93 of the Commission's Regulations shall be applicable; accordingly, in the event that any document comprising the subject Rate Schedule F–5 was executed on or after April 3, 1961, and contains provisions, either therein or by adoption of the terms and provisions of other agreements, for a change in rate other than those permitted by Section 154.93 of the Commission's Regulations, such rate change provisions shall be inoperative and of no effect at law and any tendered rate change under such provisions will be rejected.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

CALIFORNIA-PACIFIC UTILITIES COMPANY PROJECT NO. 1985

ORDER ACCEPTING SURRENDER OF LICENSE (MAJOR) AND TERMINATING PROCEEDING

(Issued June 4, 1962)

Application was filed October 31, 1960, by California-Pacific Utilities Company, licensee for major Project No. 1985, for surrender of its license for the project pursuant to Section 6 of the Federal Power Act.

The license for the project—which was located on the North and South Forks of Mill Creek in Union County, Oregon, and affected lands of the United States within the Whitman National Forest, Minan Division—was issued June 28, 1951, effective as of June 30, 1946, to California-Pacific Utilities Company for a period of 50 years.

The application stated that the project had become uneconomical to operate and maintain; that it was in need of costly repairs; and that it had not operated since August 1, 1960, when the generator was damaged by lightning and the project was taken out of service.

On January 3, 1961, the State of Oregon, through its Fish and Game Commissions, filed a petition for leave to intervene in this proceeding on the application for surrender. The petition requested that any order issued by the Commission accepting surrender of the license require the removal of diversion structures which obstructed the passage of fish. Intervention was permitted by Commission order issued February 10, 1961. The licensee has furnished the Commission a copy of a letter dated December 26, 1961, addressed to the licensee by the Oregon State Game Commission, stating that obstructions on Mill Creek have been removed sufficiently to permit uninterrupted upstream migration of fish.

By letter dated April 18, 1962, the Forest Service, United States Department of Agriculture, informed the Commission that the project works had been removed and that the restoration of the lands of the United States involved to a condition satisfactory to the Service was completed on November 3, 1961. The Forest Service stated further that the removal of the diversion dam on Mill Creek is also satisfactory to the Oregon State Game Commission.

The annual charges under the license for the project have been paid through the calendar year 1960 and the licensee's copy of the license instrument has been returned.

The Commission finds:

(1) Public notice has been given of the filing of the application for surrender of the license and no protests thereon have been received except the above-mentioned petition for leave to intervene.

(2) Acceptance of surrender of the license for the project is not inconsistent with the public interest.

The Commission orders:

Surrender of the license for major Project No. 1985 is accepted, effective as of November 3, 1961, subject to the payment of the annual charges under the license for the project through said date, in the amount of $33.72, and this proceeding is terminated.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NEW YORK STATE NATURAL GAS CORPORATION AND THE MANUFACTURER'S LIGHT & HEAT COMPANY, DOCKET NO. G–16011

ORDER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 4, 1962)

On February 12, 1962, New York State Natural Gas Corporation (New York) and The Manufacturers Light and Heat Company (Manufacturers) (sometimes hereinafter referred to jointly as Petitioners) filed in Docket No. G–16011 a joint petition to amend the Commission's order issued February 20, 1959, in Docket No. G–16011, 21 FPC 262.

The order of February 20, 1959, issued a certificate of public convenience and necessity authorizing Petitioners to exchange natural gas, pursuant to an exchange agreement, dated July 28, 1958, and to construct and to operate facili-

ties necessary therefor. Presently New York delivers natural gas produced in the Armagh Section of the Nolo Field, Indiana County, to Manufacturers and Manufacturers delivers to New York equivalent volumes of gas produced in the Benezette Field, Elk County, and the Rockton Field, Clearfield County, all in Pennsylvania.

Under the subject proposal, New York will construct 2,200 feet of 2-inch pipeline from its Learn Well No. 1 in the Jacksonville Field, Indiana County, Pennsylvania, to connect with Manufacturers' 3-inch pipeline near the Learn Well, and Manufacturers will construct and operate a measuring station at the point of interconnection. The Learn Well is not in the Armagh Section and is not, therefore, part of the presently authorized exchange arrangement. Petitioners seek to have the February 20, 1959, order amended so as to include said Learn Well production in the exchange arrangement. Petitioners have entered into an amendatory agreement, dated January 29, 1962, to provide for the Learn Well production.

The estimated cost of New York's and Manufacturers' proposed facilities is $3,000 and $1,600, respectively.

Due notice of the filing of the petition to amend and opportunity for hearing thereon has been given by publication in the Federal Register on April 28, 1962, (27 FR 4108). No protest or petition to intervene has been filed in this proceeding.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act, and the public convenience and necessity require that the Commission's order issued February 20, 1959, in Docket No. G–16011, be amended as hereinafter ordered.

The Commission orders:

(A) The Commission's order issued February 20, 1959, in Docket No. G–16011, is hereby amended so as to authorize Petitioners, New York State Natural Gas Corporation and The Manufacturers Light and Heat Company, to construct and operate the proposed facilities and to authorize the inclusion of gas from New York's Learn Well No. 1 as part of the gas exchanged between Petitioners.

(B) In all other respects, said order shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

OAKDALE IRRIGATION DISTRICT AND SOUTH SAN JOAQUIN IRRIGATION DISTRICT PROJECT NO. 2005

ORDER WAIVING IMPOSITION OF PENALTY FOR DELINQUENCY IN PAYMENT OF ANNUAL CHARGES

(Issued June 4, 1962)

On March 5, 1962, a statement of the annual charges for the calendar year ended December 31, 1961 under the license for Project No. 2005 was mailed to Oakdale Irrigation District and South San Joaquin Irrigation District, joint licensees for the project. It was noted on the statement that the charges should be paid "within 30 days of rendition of a bill therefor".

Since payment was not received within the period specified, the licensees were reminded by letter of April 20, 1962 of the delinquency in payment, whereupon

payment, in the amount of $3,621.92 was made on April 25, 1962. Such prompt action to our reminder would indicate that the delay was unintentional.

Annual charges for Project No. 2005 did not commence until May 5, 1957 and no statement for the 1957 and 1958 charges was rendered until March 27, 1959. By our order issued July 20, 1960, 24 FPC 60, the license for Project No. 2005 was amended effective as of January 1, 1958 to substitute the new charge formula for State and municipal licensees determined in Docket No. R–129 by our Order No .205 dated June 6, 1958. Since application of the new charge formula to Project No. 2005 substantially reduced the administrative charges under the license for that project back to January 1, 1958, payment of the 1957 and 1958 charges on the old basis created a credit balance in favor of the licensees. Accordingly, no statement requiring payment of the 1959 and 1960 charges was rendered, and our statement for the 1961 charges was only the second rendered that required payment. The charge of $3,621.92 reflected the balance due after exhausting the remaining credit against th 1961 charges. (The licensees also hold the license for Project No. 2067 which has a credit balance remaining after deducting 1961 annual charges applicable thereto.)

The Commission finds:

In the circumstances, it will not be inconsistent with the public interest to waive imposition of any penalty by reason of the licensees' delay in payment of the annual charges.

The Commission orders:

The imposition of any penalty by reason of the delay of the joint licensees in the payment of the annual charges under the license for Project No. 2005 for the calendar year 1961 is waived.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NORTHERN NATURAL GAS COMPANY DOCKET NO. CP61–213

ORDER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 5, 1962)

On March 2, 1962, Northern Natural Gas Company (Petitioner) filed a petition to amend the Commission's order issued November 6, 1961, in Docket No. CP61–213, 26 FPC 709, so as to authorize Petitioner to sell and deliver to Public Service Corporation of Texas (Public Service) up to 3,500 Mcf of natural gas per day, on an interruptible basis, rather than the 1,500 Mcf per day, on an interruptible basis, authorized by said order.

The 1,500 Mcf per day authorized in the order of November 6, 1961, was to assist Public Service in meeting the increasing peak period requirements of its customers. The subject Petition indicates that the authorized volumes have proved inadequate and that in order to alleviate future peak day deficiencies in gas supply, Public Service has requested Petitioner to supply up to 3,500 Mcf per day in lieu of 1,500 Mcf per day.

Petitioner and Public Service have entered into an amendatory agreement, dated February 9, 1962, providing for the increased service. Such service is to be rendered under the same terms and price as the presently authorized service.

Due notice of the filing of the petition to amend and opportunity for hearing thereon has been given by publication in the Federal Register on May 4, 1962,

(27 FR 4316). No protest or petition to intervene has been field in this proceeding.

The Commission finds:

It is necessary and appropriate to carry out the provisions of the Natural Gas Act, and the public convenience and necessity requires that the Commissioner's order issued November 6, 1961, in Docket No. CP61–213, be amended as hereinafter ordered.

The Commission orders:

(A) Ordering paragraph (A) of the Commission's order issued November 6, 1961, in Docket No. CP61–213, as hereby amended to read as follows:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Northern Natural Gas Company, to sell and deliver up to 3,500 Mcf of interruptible natural gas per day, to Public Service Corporation of Texas as hereinbefore described, all as more fully described in the application, as supplemented, herein, upon the terms and conditions of this order.

(B) In all other respects, said order shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

SOUTHERN NATURAL GAS COMPANY; TENNESSEE GAS TRANSMISSION COMPANY DOCKET NO. G–4715

FINDINGS AND ORDER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 5, 1962)

On March 14, 1962, Southern Natural Gas Company (Southern) and Tennessee Gas Transmission Company (Tennessee) filed in Docket No. G–4715 a joint petition to amend the certificate of public convenience and necessity heretofore issued in said docket, all as more fully set forth in the joint petition.

By order of the Commission issued February 25, 1955, 14 FPC 577, in the subject docket, Petitioners were authorized to exchange natural gas. Southern was authorized to deliver gas from production owned or controlled by it in the Franklin Field, St. Mary Parish, Louisiana, to Tennessee's lines in that field, and Tennessee was authorized to return gas by delivering equivalent quantities to Southern at a point approximately 12 miles south of the Franklin Field, near Tennessee's gas receiving station at the end of its Bayou Sale lateral line.

Petitioners request the Commission to amend the certificate issued to them in the subject docket as follows:

(1) To authorize a new delivery point in the immediate vicinity of Southern's existing Eloi Bay receiving station; and to authorize Tennessee to deliver to Southern at the Eloi Bay delivery point, pursuant to the Franklin Exchange Agreement, up to 4,000 Mcf of gas per day, with a corresponding reduction in the amount of gas redelivered by Tennessee to Southern under the Franklin Exchange Agreement at the Bayou Sale delivery point; and

(2) To authorize Southern to tap its Eloi Bay lateral and to construct and operate measuring and receiving facilities at the Eloi Bay delivery point for the receipt of said gas from Tennessee.

Construction, operation, and maintenance costs for the measuring and regulating station will be borne by the producers.

Notice of the petition was published in the Federal Register on May 11, 1962 (27 FR 4537).

The Commission finds:

It is required by the public convenience and necessity and is appropriate in carrying out the provisions of the Natural Gas Act that the Commission's order of February 25, 1955, in Docket No. G–4715 (14 FPC 577) should be amended to authorize the additional exchange point for natural gas and the construction and operation of facilities therefor, as hereinbefore described and as more fully described in the joint petition herein.

The Commission orders:

(A) The Commission's order of February 25, 1955, in Docket No. G–4715 (14 FPC 577) be and the same is hereby amended to authorize the additional exchange point for natural gas and the construction and operation of facilities necessary therefor, as hereinbefore described and as more fully described in the joint petition herein.

(B) In all other respects said order of February 25, 1955, shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

REVISION OF ANNUAL REPORT FORM PRESCRIBED FOR CLASS C AND CLASS D NATURAL GAS COMPANIES SUBJECT TO THE NATURAL GAS ACT, F.P.C. FORM NO. 2–A DOCKET NO. R–211

ORDER NO. 249

ORDER PROMULGATING A REVISED ANNUAL REPORT FORM FOR CLASS C AND CLASS D NATURAL GAS COMPANIES

(Issued June 6, 1962)*

The Commission has under consideration in this proceeding the revision of its F.P.C. Form No. 2–A, Annual Report Form Prescribed for Class C and Class D Natural Gas Companies[1] Subject to the Provisions of the Natural Gas Act and § 260.2, Part 260, Subchapter G, Approved Forms, Natural Gas Act, Chapter I, Title 18, Code of Federal Regulations (CFR), prescribing F.P.C. Form No. 2–A. That Report Form, as revised, is prescribed hereinafter effective for use in reporting for the calendar year beginning January 1, 1961 or subsequently during the calendar year 1961 if an established fiscal year is other than the calendar year, and years thereafter.

The various schedules comprising F.P.C Form No. 2–A now prescribed in § 260.2 (18 CFR 260.2), correspond to, and appear as pages 1–19 of the Commission's F.P.C. Form No. 2–A, Natural Gas Companies, Class C and Class D.[2]

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* Published in the Federal Register on June 13, 1962, (27 F.R. 5606)

[1] Commission Order No. 231 issued December 21, 1960 (24 FPC 1117) (25 F.R. 13882, December 29, 1960), prescribed F.P.C. Form Nos. 301–A and 301–B as the annual financial report for independent producers of natural gas.

[2] Form No. 2–A was prescribed by Order No. 90 of February 7, 1942 (7 F.R. 1018, February 17, 1942). It was thereafter amended by Order No. 150 of November 22, 1949 (14 F.R. 7248, December 2, 1949) and by Order No. 171–A of May 17, 1954 (10 FPC 1051) (19 F.R. 2965, May 21, 1954).

This proceeding was commenced by notice of proposed rule making served upon interested parties, including States and Federal regulatory agencies, and by publication in the Federal Register on April 4, 1962 (27 F.R. 3207). As proposed, the subject matters and revisions in § 260.2, and the General Instructions and other Schedules comprising F.P.C. Form No. 2–A were set forth in the notice of proposed rule making and attached forms of proposed revised Schedules served upon the aforesaid interested parties and filed as a part of the notice submitted to the Federal Register for publication. The notice of proposed rule making invited the submission to the Commission of written data, views, comments and suggestions concerning the proposed revisions of F.P.C. Form N. 2–A and Part 260 on or before April 20, 1962. No filing responsive to the notice of proposed rule making has been received.

The exact nature of each of the revisions in Form 2–A is fully set forth in the respective accompanying schedule pages. The changes would be accomplished mainly through modification of existing schedules. Six new schedules would be added: Security Holders and Voting Powers; Officers and Directors; Capital Stock; Long-Term Debt; Sales of Natural Gas for Resale; and Gas Purchases. Two existing schedules will be omitted: Gas Plant in Process of Reclassification, and System May (Class C Natural Gas Companies). The revised Annual Report Form has been adapted to changes prescribed in the Uniform System of Accounts, prescribed for Natural Gas Companies effective January 1, 1961.

The Commission finds:

(1) The notice and opportunity to comment in this rule making proceeding with respect to the matters presently before the Commission in the manner as described above are consistent and in accordance with the procedural requirements of Section 4 of the Administrative Procedure Act.

(2) In view of the foregoing, and upon consideration of all relevant matters presented it is necessary and appropriate for the purposes of the Natural Gas Act that:

(a) The revised Annual Report Form as set forth in annexed Appendix A be adopted and promulgated as this Commission's F.P.C. Form No. 2–A effective for use in reporting for the calendar year beginning January 1, 1961 or subsequently during the calendar year if an established fiscal year is other than the calendar year, and years thereafter; all as hereinafter provided.

(b) Section 260.2, Part 260, Subchapter G, Approved Forms, Natural Gas Act, Chapter I, Title 18, Code of Federal Regulations be amended to read as hereinafter provided.

(3) Good cause exists for the adoption and promulgation of the matters referred to above immediately upon issuance of this order; all as hereinafter provided.

The Commission acting pursuant to the Natural Gas Act, as amended, particularly Sections 8, 9, 10 and 16, thereof (52 Stat. 825, 826, 826; 830; 15 U.S.C. 717g, 717h, 717i and 717o) *orders:*

(A) The revised Report Form as set forth in annexed Appendix A is adopted and promulgated as this Commission's F.P.C. Form No. 2–A effective for use in reporting for the calendar year beginning January 1, 1961, or subsequently during the calendar year 1961 if an established fiscal year is other than the calendar year, and years thereafter.

(B) Sction 260.2, Part 260, Subchapter G, Approved Forms Natural Gas Act, Chapter I, Title 18, Code of Federal Regulations, is amended to read as follows:

§ 260.2 *Form No. 2–A; Annual report for natural gas companies (Class C and Class D).*

(a) The form of Annual Report for natural gas companies, Class C and Class D, designated as F.P.C. Form No. 2–A in the Commission's Regulations under the Natural Gas Act is prescribed for the year 1961 and thereafter.

(b) Each natural gas company, as defined in the Natural Gas Act which is included in Class C or Class D as defined in the Commission's Uniform System of Accounts Precribed for Natural Gas Companies, effective January 1, 1961, shall prepare and file with the Commission for the year beginning January 1, 1961, or subsequently during the calendar year 1961 if its established fiscal year is other than the calendar year, and for each year thereafter, on or before the last day of the third month following the close of the calendar year or other established fiscal year (except that such reports for the calendar year 1961 or a fiscal year beginning during 1961 may be filed on or before July 16, 1962 or one month after the end of the fiscal year whichever is later) an original and one conformed copy of the above-designated F.P.C. Form 2–A, all properly filled out and verified. One copy of said report should be retained by the correspondent in its files. The confirmed copy may be a carbon copy if legible

(c) This annual report contains the following schedules:

Identification
General Instructions
General Information
Security Holders and Voting Powers
Officers and Directors
Comparative Balance Sheet
Accumulated Provision for Depreciation, Depletion and Amortization of Utility Plant
Capital Stock
Long-Term Debt
Condensed Income Statement for the Year
Earned Surplus
Gas Sales Data for the Year
Gas Operation and Maintenance Expenses
Sales for Resale—Natural Gas
Gas Purchases
Utility Plant Natural Gas Companies
Gas Account—Natural Gas
General Information Concerning Plant and Operations
Verification

[Authority: Sections 8, 9, 10 and 16, 52 Stat. 825, 826, 826, 830; 15 U.S.C. 717g, 717h, 717i and 717o.]

(C) This order shall be effective upon the date of issuance thereof.

(D) The Secretary of the Commission shall cause prompt publication of this order to be made in the Federal Register.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

EL PASO NATURAL GAS COMPANY, DOCKET NO. G–104

ORDER AUTHORIZING EXPORTATION OF NATURAL GAS

(Issued June 7, 1962)

El Paso Natural Gas Company (El Paso), a Delaware corporation with principal place of business in El Paso, Texas, filed an application for an order

in Docket No. G–104 on May 7, 1962, pursuant to Section 3 of the Natural Gas Act (Act), authorizing it to continue the exportation of natural gas from the United States to Mexico as hereinafter described, subject to the jurisdiction of the Commission, all as more fully set forth in said application which is on file with the Commission.

El Paso is the holder of a Presidential Permit which was issued to it on September 5, 1940, pursuant to Executive Order No. 8202 of July 13, 1939. This Presidential Permit is presently in full force and effect and authorized the continued operation, maintenance and connection of the presently existing facilities at the border of the United States and Mexico, at or near Monument 90 on the International Boundary which is located approximately 7¾ miles east of Naco, Cochise County, Arizona.

By order issued on September 10, 1940 (unreported), El Paso was authorized, pursuant to Section 3 of the Act and subject to the terms and conditions set forth in said order, to continue the exportation of natural gas from the United States to Mexico in accordance with a gas sale contract between Western Gas Company (seller), a Delaware corporation, and The Cananea Consolidated Copper Company, S.A. (buyer), a Mexican corporation, dated August 6, 1930, as amended December 18, 1934, which was acquired by El Paso from the Western Gas Company through assignment on June 11, 1936. At the time of issuance of that order, The Cananea Consolidated Copper Company, S.A. was a subsidiary of the Greene Cananea Copper Company. This order was superseded, and not amended, by an order subsequently issued on November 12, 1947, which is reported at 6 FPC 1005. The order of November 12, 1947, which is presently in effect, was based upon an agreement between El Paso and the Greene Cananea Copper Company, dated February 4, 1947, which, in effect, renewed the El Paso-Cananea Consolidated Copper Company contract "for a period of fifteen years from June 8, 1947". This order authorized El Paso, pursuant to Section 3 of the Act and subject to the terms and conditions set forth in said order, to continue the exportation of natural gas from the United States to Mexico in accordance with the contract, as renewed, "for a period not to exceed 15 years from June 8, 1947". This Section 3 authorization to export natural gas will expire, along with the contract involved, on June 8, 1962.

Under the existing export operation, El Paso delivers natural gas at the border of the United States and Mexico, near Monument 90, to Compania Occidental de Gas, S.A., de Capital Variable (Occidental) for the account of The Cananea Consolidated Copper Company. Occidental, a Mexican corporation and a wholly-owned subsidiary of El Paso, owns and operates an 8⅝-inch natural gas pipeline which is located entirely within Mexico. Occidental's line, which is approximately 39 miles in length, connects with the natural gas facilities of El Paso at the border, near Monument 90, and extends from that point in a southwesterly direction to the municipality of Cananea, Sonora, Mexico. After taking delivery of the gas from El Paso at the border, Occidental transports it through its line and delivers the same to The Cananea Consolidated Copper Company at or near the municipality of Cananea pursuant to a transportation agreement between Occidental and The Cananea Consolidated Copper Company, dated June 1, 1931, and otherwise having a term co-extensive with the aforesaid contract for the sale of gas between El Paso and The Cananea Consolidated Copper Company.

The Cananea Consolidated Copper Company uses the gas at its mine, smelter and plants located at or near Cananea and also supplies gas to the Compania de Gas de Cananea, S.A., a Mexican corporation unaffiliated with El Paso or The Cananea Consolidated Copper Company, for distribution in the town of Cananea, Sonora, Mexico.

By its present application, El Paso proposes to continue the exportation of natural gas from the United States to Mexico by means of existing and authorized facilities, as hereinbefore described, in accordance with a gas sale contract between El Paso, as seller, and Compania Minera de Cananea, S.A. de C.V., as buyer, hereinafter referred to as Minera. Minera, a Mexican corporation, is successor in interest to The Cananea Consolidated Copper Company and is a subsidiary of, and controlled by, the Greene Cananea Copper Company, a Minnesota corporation. This contract, dated June 9, 1962, will expire on June 1, 1972, unless terminated sooner in accordance with its provisions and deliveries are to commence thereunder on June 9, 1962. The agreement provides for the sale by El Paso of all of the natural gas fuel requirements for Minera's smelter and related mining operations in Cananea, Sonora, Mexico, plus such additional amounts of gas as Minera may take from time to time for domestic and industrial use by third parties in the vicinity of Cananea, Sonora, Mexico. El Paso's total obligation to deliver gas under the agreement is limited to amounts not in excess of 10,000,000 cubic feet per day. As under the earlier arrangement heretobefore described, El Paso will make deliveries of the gas through its existing facilities at the border, near Monument 90, to Occidental for the account of Minera. The El Paso-Minera contract provides for the sale of natural gas at the rate now or hereafter provided for gas delivered under Rate Schedule B–1 of El Paso's FPC Gas Tariff, Original Volume #1. The present rate applicable for the instant gas under this rate schedule is stated to be 35.65 cents per Mcf at 14.9 psia.

El Paso has also entered into a contract with the Greene Cananea Copper Company (Greene), dated June 9, 1962, whereunder El Paso guarantees the performance of Occidental under a transportation agreement btween Occidental and Minera, also dated June 9, 1962, as long as El Paso controls Occidental and whereunder Greene guarantees the performance of Minera under the El Paso-Minera gas sale contract as long as Greene controls Minera. The Occidental-Minera transportation agreement supersedes the Occidental-Cananea Consolidated Copper Company transportation contract hereinbefore described.

Natural gas has been exported continuously since June 8, 1931, to The Cananea Consolidated Copper Company, S.A., the predecessor of Minera. No additional facilities will be required for the continued exportation of natural gas, as proposed. The continued exportation and sale of natural gas, as proposed, will not impair El Paso's ability to render natural gas service to its customers in the United States.

Notice of the filing of the instant application was issued on May 23, 1962. This notice fixed June 5, 1962, as the last day for filing protests or petitions to intervene. No protests, petitions to intervene or notices of intervention have been filed or received. Opportunity for hearing has been given by the issuance of said notice and the publication thereof in the Federal Register on May 29, 1962 (27 FR 5015).

The Commission further finds:

The continued exportation of natural gas by El Paso from the United States to Mexico in accordance with the Minera contract will not be inconsistent with the public interest within the meaning of Section 3 of the Act provided that said exportation be continued on the terms and conditions hereinafter set forth, to wit:

(a) El Paso shall file statements or reports with the Commission from time to time under oath and in such details as the Commission may require with respect to the whole or any part of the instant export operation.

(b) The authorization granted herein is not transferable or assignable and shall remain in full force and effect only so long as El Paso continues the acts or operations herein authorized in accordance with the terms and conditions herein set forth.

(c) The authorization granted herein shall automatically terminate upon the termination or expiration of the contract between El Paso Natural Gas Company (seller) and Compania Minera De Cananea, S.A. de C.V. (buyer), dated June 9, 1962, and attached as an exhibit to the application filed in Docket No. G–104 on May 7, 1962, and which provides for the sale and exportation of natural gas to Mexico, and, upon the termination of said contract by discharge as a result of performance or completion, El Paso shall forthwith notify the Commission in writing of the fact and date of said termination.

(d) El Paso shall not, during the term of the authorization granted by this order, materially change or alter its export operations without first obtaining the permission and approval of the Commission.

(e) In the event that El Paso should abandon or permanently cease for any reason whatsoever all or any part of the instant export operation prior to the termination date of the contract described in (c) hereof, El Paso shall forthwith notify the Commission of said fact and the reason therefor.

The Commission orders:

(A) An order be and the same is hereby issued to El Paso in Docket No. G–104, pursuant to the aforesaid finding and subject to the terms and conditions set forth in subsections (a) through (e) thereof, authorizing El Paso to continue the exportation of natural gas from the United States to Mexico in accordance with the contract between El Paso and Compania Minera De Cananea, S.A. de C.V., dated as of June 9, 1962.

(B) The order issued in paragraph (A) hereof shall become effective upon the expiration of the order of the Commission issued in Docket No. G–104 on November 12, 1947, so that no interruption of service will occur.

Before Commissioners: L. J. O'Connor, Jr., Acting Chairman; Charles R. Ross and Harold C. Woodward.

GAS PURCHASE FACILITIES—BUDGET-TYPE CERTIFICATE APPLICATIONS, PIPELINE COMPANIES, DOCKET NO. R–216

ORDER NO. 247

STATING GENERAL POLICY

(Issued June 7, 1962)*

The Commission has before it for consideration the issuance of a statement of general policy by the addition of a new § 2.58 to Part 2, Subchapter A, General Rules, Chapter I of Title 18, Code of Federal Regulations.

After considering certain suggestions made in a rulemaking proceeding, Docket No. R–145, then pending before it, the Commission issued its Order No. 185 on February 8, 1956 (15 FPC 793; 21 F.R. 1485) stating therein that

> . . . the Commission advises any interested natural gas company, subject to the Natural Gas Act, that it may file under Section 157.6 of the Rules, a single certificate application covering in general outline along the lines

* Published in the Federal Register on June 13, 1962 (27 F.R. 5606).

of a budget estimate the proposed routine construction intended to be undertaken by it during the current or ensuing fiscal year, listing the facilities proposed, the estimated cost of each item, the capacity, purpose and time of intended construction, customers affected by each facility proposed, effect of proposals upon gas supply and deliverability, rates, service and other pertinent information. A hearing could then be held on such a proposal and certificate issued in accordance with the general application. At the end of the period, a statement shall be filed, showing the action taken under the certificate and any authority thereunder which was not exercised. (Id. at 794.)

Pursuant to our suggestion in that order, natural gas pipeline companies have filed applications for budget authority to construct and operate gas purchase facilities. Authorizations have been issued during the past several years on a case-by-case basis. It is believed that the industry should now be informed as to the factors we will consider in the issuance of such budgetary authorizations based upon our experience in disposing of such applications. Accordingly, we are issuing the statement adopted herein.

The Commission finds:

(1) The amendment to Part 2 of the Commission's Rules herein adopted represents matters of policy and procedure which do not require notice or hearing under section 4(a) of the Administrative Procedure Act.

(2) Adoption and promulgation of the proposed amendment is necessary and appropriate for the purpose of administration of the Natural Gas Act.

The Commission, acting pursuant to the authority granted by the Natural Gas Act, as amended, particularly section 7 and 16 thereof (52 Stat. 824, 830; 56 Stat. 83; 15 U.S.C. 717f, 717o), *orders:*

(A) Part 2, Subchapter A, General Rules, Chapter I of Title 18 of the Code of Federal Regulations is amended by adding a new § 2.58 to read as set out in the attachment hereto.

(B) The statement and amendment herein prescribed shall become effective upon the issuance of this order.

(C) The Secretary shall cause prompt publication of this order to be made in the Federal Register.

Attachment

Part 2—General Policy and Interpretations

* * *

§ 2.58 *Budget-type certificate applications—gas purchase facilities.*

In accordance with the Commission's advise in Order No. 185, issued February 8, 1956 (15 FPC 793 at 794) and unless prevented by other factors, such as interventions in opposition, we will issue budget-type authorizations to natural gas pipeline companies covering the construction and operation of gas purchase facilities, after hearing under the abridged procedure, upon applications for certificates of public convenience and necessity, filed under § 157.6 of this chapter, provided that:

(a) The total estimated cost of the facilities to be installed in a given twelve-month period does not exceed 1½ percent of the applicant company's plant account or $5,000,000 whichever is the lesser.

(b) The total cost of any single project facilities to be installed during the authorization period does not exceed 25 percent of the total budget amount or $500,000, whichever is the lesser.

(c) The applicant agrees to file with the Commission, within sixty days after expiration of the authorization, a statement showing for each individual project:

(1) Description of facilities installed, i.e., miles and size of pipelines, compressor horse-power, metering facilities.

(2) Location of facilities.

(3) Actual installed cost of facilities subdivided by size of pipe, compressing, metering and appurtenant facilities.

(4) Estimated recoverable gas reserves in Mcf at 14.73 psia made available to applicant by means of the facilities.

(5) Names of fields connected.

(6) The names of the independent producers from whom the gas is being purchased together with the respective dates of the gas sales contracts and the docket number of the related seller.

(d) "Gas purchas facilities" means those facilities necessary to connect the applicant's system with the facilities of a seller authorized by this Commission to make a sale for resale in interstate commerce to the applicant.

[Authority: Sec. 7, 56 Stat. 83; sec. 16, 52 Stat. 830; 15 U.S.C. 717f, 717o]

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

CUSTODY, AUTHENTICATION AND CERTIFICATION OF DOCUMENTS, DOCKET NO. R-217

ORDER NO. 248

AMENDING THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE

(Issued June 7, 1962)*

This order amends sections 1.2(a) and 1.14(b), respectively, of the Commission's Rules of Practice and Procedure so as to reflect certain procedures previously established by administrative order.

The Commission finds:

(1) The adoption of appropriate amendments will correlate pertinent sections of the Rules of Practice and Procedure with Administrative Order No. 89.

(2) The promulgation and adoption of the following amendments are necessary for the purposes of administration of both the Federal Power Act and the Natural Gas Act.

(3) Since the amendments herein adopted involve matters of practice and procedure, notice or hearing under section 4(a) of the Administrative Procedure Act is not required.

The Commission, acting pursuant to authority granted by the Federal Power Act, particularly sections 308 and 309 thereof (49 Stat. 858; 16 U.S.C. 825g, 825h), and the Natural Gas Act, as amended, particularly sections 15 and 16 thereof (52 Stat. 829, 830; 15 U.S.C. 717n, 717o), *orders:*

(A) Part 1, Rules of Practice and Procedure, of Subchapter A, General Rules, Chapter I of Title 18 of the Code of Federal Regulations, is amended as follows:

1. In § 1.2 *The Secretary*, subsection (a) is amended to read as follows:

"(a) *Official records* (1) The Secretary shall have custody of the Commission's seal, the minutes of all action taken by the Commission, its rules and regulations and its administrative orders.

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* Published in the Federal Register on June 13, 1962 (27 F.R. 5605).

(2) The Records Officer shall have custody of all records of the Commission except those designated in paragraph (1) hereof."

2. In § 1.14 *Filings; docket; hearing calendar*, subsection (b) *Docket* is amended by changing "Secretary" to read "Records Officer".

[Authority: Sections 308, 309, 49 Stat. 858, sections 15, 16, 59 Stat. 829, 830; 16 U.S.C. 825g, 825h; 15 U.S.C. 717n, 717o.]

(B) These amendments shal lbecome effective upon issuance of this order.

(C) The Secretary shall cause publication of this order to be made in the Federal Register.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TEXAS EASTERN TRANSMISSION CORPORATION, DOCKET NOS. CP60-122 AND CP61-203; ALGONQUIN GAS TRANSMISSION CORPORATION, DOCKET NOS. CP60-124 AND CP61-220; UNITED GAS PIPE LINE COMPANY, DOCKET NO. CP61-151; SOUTHERN NATURAL GAS COMPANY, DOCKET NO. CP61-206; TEXAS GAS TRANSMISSION CORPORATION, DOCKET NO. CP61-247; ARKANSAS MISSOURI POWER COMPANY, DOCKET NO. CP62-20

ORDER PROVIDING FOR FILING OF BRIEFS

(Issued June 7, 1962)

Formal hearings in the above-captioned consolidated section 7(c) applications were concluded on May 16, 1962. Dates for filing of briefs have been set as follows: Applicants' Initial Briefs, June 11, 1962; Answers by Staff and interveners, July 9, 1962; Reply Briefs by Applicants, July 23, 1962.

On April 18, 1962, applications for temporary authority to construct certain facilities and to make additional sales were filed by Texas Eastern Transmission Corporation (Texas Eastern) in Docket No. CP61-203, Algonquin Gas Transmission Company (Algonquin) in Docket No. CP61-220 and Texas Gas Transmission Corporation (Texas Gas) in Docket No. CP61-247. United Gas Pipe Line Company(United), filed an application for temporary authority in Docket No. CP61-151 on April 18, 1962, to make additional sales. Southern Natural Gas Company filed an application on April 23, 1962 in Docket No. CP61-206, for temporary authority to construct facilities and make additional sales to Texas Eastern. Each of the above-mentioned Applicants claims that an emergency exists which requires the issuance of the temporary authority sought, as more fully set out in the applications on file with the Commission and open to public inspection.

A statement in support of the temporary authorizations requested by Texas Eastern and Algonquin was filed by the New England Distributor Interveners[1] on May 7, 1962. A statement in support of all of the temporary authorizations requested was filed by the Consolidated Edison Company of New York, Inc. on

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[1] Boston Gas Company
Brocton Gas Company
Buzzards Bay Gas Company
The Connecticut Gas Company
The Hartford Electric Light Company
The Hartford Gas Company
New Haven Gas Company
City of Norwich, Department of Public Utilities
Norwood Gas Company
Providence Gos Company
Worcester Gas Light Company

May 10, 1962. An answer in opposition to all of the above requests for temporary authority was filed by the Coal Interveners[2] on April 27, 1962.

In order for the Commission to properly dispose of these interrelated applications for temporary authorizations it is desirable that all parties file briefs directed to the questions as to whether these requests should be granted in whole or in part, or be denied.

The Commission orders:

All parties to the above-captioned proceedings are hereby provided an opportunity to file briefs on or before June 18, 1962, directed to the question whether the applications for temporary authority above referred to should be granted in whole or in part, or be denied.

[2] Fuels Research Council, Inc.; United Mine Workers of America; National Coal Association; Anthracite Institute.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

FLORIDA GAS TRANSMISSION COMPANY,[1] DOCKET NOS. G–9262, RP61–3, RP62–4; COASTAL TRANSMISSION CORPORATION, DOCKET NO. G–9960, RP61–4

ORDER ACCEPTING PROPOSED SETTLEMENT, MODIFYING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY, SEVERING AND TERMINATING CERTAIN PROCEEDINGS, TERMINATING OTHER PROCEEDINGS IN PART, AND DISCHARGING REFUND OBLIGATIONS

(Issued June 8, 1962)

On April 18, 1962, Florida Gas Transmission Company (Florida Gas) and Coastal Transmission Corporation (Coastal) submitted a proposed settlement in the above-listed consolidated proceedings. The hearing on the consolidated proceedings was recessed on April 2, 1962, for the purpose of holding conferences, looking towards limitation and settlement of issues. On April 30, 1962, the Presiding Examiner certified to the Commission the stipulation and agreement (Tr. 4586 to 4617) which resulted from said conferences, and which, in part, is attached hereto as Exhibit I.[2] No objections to the proposed settlement have been received from any party to these proceedings.

The proceeding in Docket No. RP61–3 involves proposed increases in rates by Florida Gas under its Rate Schedules G, T–1, and T–2, and a discount under its Rate Schedule G for gas used by consumers for winter heating and summer cooling. The proceedings in Docket Nos. G–9262 and G–9960 involve proposed modifications of the certificates of public convenience and necessity issued to Florida Gas and Coastal (16 FPC 118) to eliminate specific requirements as to rate of return, form of tariff, an dseparation of charges for sales and transportation. Coastal's proposed amendment to its certificate resulted in an increase in its cost of service tariff for sales of natural gas for resale to Florida Gas, which proposed increase was suspended in Docket No. RP61–4. The pro-

[1] Formerly Houston Texas Gas and Oil Corporation.

[2] For convenience only, the text of the agreement and Appendix B are attached hereto. Appendices A, C and D, not here reproduced, are comprised of revised tariff sheets to be filed by the companies pursuant to the terms of the settlement. [Exhibit I, omitted in printing.]

ceeding in Docket No. RP62–4 involves a proposed waiver of the minimum bill provisions under Florida Gas' Rate Schedule I.

The offer of settlement provides that Florida Gas will file with the Commission revised tariff sheets proposed to be effective as of May 1, 1962, containing the following base rates:

Rate Schedule G	57.0 cents per MMBtu base price
	15.0 cents per MMBtu air conditioning discount
Rate Schedule T–1	14.5 cents per MMBtu
Rate Schedule T–2	18.5 cents per MMBtu

In addition, the revised tariff sheets would change the present application of the minimum bill provision in Rate Schedule G from a monthly basis to a calendar year basis, include a one-year make up provision for gas paid for but not taken by the buyer under such rate schedule provision, and would reduce the minimum bill in Florida Gas' Rate Schedule I to zero. It is further stipulated that Florida Gas will not file for increases in its Rate Schedules G, I, T–1 and T–2 above the rates contained in the agreement, which would be made effective (after suspension) prior to January 1, 1964, except to recoup increased costs resulting from purchased gas costs and increased taxes where the aggregate effect could result in an annual increase of $200,000 or more in costs applicable to resale jurisdictional sales.

The aforesaid stipulation and agreement provide that two issues be reserved for further conference and hearing, if necessary, in the proceedings in Docket Nos. RP61–3 and RP61–4. Those issues involve: (1) the proper cost for accounting purposes under the Uniform System of Accounts of constructing the facilities of Florida Gas and (2) the accrual for Federal income taxes on the books of Coastal for accounting purposes under the Uniform System of Accounts.

The offer of settlement also provides that the rate conditions set forth in the Commission's order and opinion issued December 28, 1956 in Docket Nos. G–9262 and G–9960 (16 FPC 118) be amended so that the words "in accordance with usual Commission standards and based on an annual rate of return of not in excess of 6 percent" be deleted from ordering clause (B)(1) and that ordering clause (C)(3) be changed by substituting 6.5 for 6 percent in such clause on and after May 1, 1962. The modification of Florida Gas' certificate will enable it to file a tariff change, under Section 4 of the Natural Gas Act and the Regulations with respect thereto, without requesting or obtaining prior concurrent modification under Section 7 of the Natural Gas Act of its certificates of public convenience and necessity presently outstanding.

In their offer of settlement, Florida Gas and Coastal state and agree that they will diligently prosecute their application, filed on April 2, 1962 in Docket No. CP62–232, to merge Coastal into Florida Gas.

Our review of the terms of the settlement agreement and the studies in support thereof indicates that said agreement and settlement of these proceedings is in the public interest and should be approved.

The Commission finds:

The proposed settlement submitted by Florida Gas and Coastal on April 18, 1962 in these proceedings and which, in part, is attached hereto as Exhibit I, is reasonable and proper and in the public interest in carrying out the provisions of the Natural Gas Act, and should be approved as hereinafter provided.

The Commission orders:

(A) The increased rates and charges filed by Florida Gas and Coastal in these consolidated proceedings are hereby disallowed and denied, as of May 1, 1962.

(B) The settlement of these proceedings on the basis of the stipulation and agreement set forth in the transcript of these proceedings (Tr. 4586 to 4617), is approved and made effective, subject to the terms and condition hereinafter specified.

(C) Within 30 days after the date of issuance of this order, Florida Gas shall file, in a form satisfactory to the Commission, revised tariff sheets in conformity with the requirements of the said stipulation to be effective as of May 1, 1962.

(D) Ordering Clause (B) (1) of the order issued December 28, 1956 (16 FPC 118 at p. 114) is amended to read as follows:

The rates set forth in the tariffs for firm sales for resale, interruptible sales, and for transportation, shall be commensurate with the cost of service determined on a reasonable allocation of costs between these services.

(E) Ordering Clause (C) (3) of the order issued December 28, 1956 (16 FPC 118 at p. 145) is hereby modified to the extent and only to the extent of substituting "6.5" percent for "6" percent in such clause, effective on and after May 1, 1962.

(F) Within 60 days from the date of issuance of this order, the Commission staff shall convene a conference between the parties and interveners in Docket Nos. RP61–3 and RP61–4 at a convenient date and place for the purpose of discussing and deciding upon the procedure to be followed in disposing of the reserved issues set forth in Article VI of said stipulation and, if possible, to define and reduce said reserved issues.

(G) Upon full compliance by Florida Gas and Coastal with all the terms and provisions of this order and the said stipulation, each of the above-entitled proceedings are hereby severed from the above-entitled consolidated proceedings and shall be deemed terminated, except as to the reserved issues defined in Article VI of said stipulation, which issues remain outstanding in Docket Nos. RP61–3 and RP61–4.

(H) Upon compliance with paragraph (C) above, Florida Gas and Coastal are hereby released and discharged from any and all obligations under their respective bonds filed in these proceedings.

(I) This order is without prejudice to any findings or orders which have been or may hereafter be made by the Commission and is without prejudice to any claims or contentions which may be made by the Commission, Florida Gas, Coastal or any other part affected by this order, in any proceeding now pending or hereafter instituted by or against Florida Gas and/or Coastal or any other person.

Appendix B

Stipulation and Agreement

Dated Apr. 17, 1962

Florida Gas Transmission Company, Annual Effect of Settlement Rates

Rate schedule	Annual volumes per exhibit 95 (M^3Btu)	Revenues computed at filed rates	Revenues computed at settlement rates	Decrease in revenues
G	10, 119, 564	$5, 970, 543	$5, 768, 151	$202, 392
I	7, 632, 721	2, 518, 798	2, 518, 798	
T–1	18, 217, 568	2, 732, 635	2, 641, 547	91, 088
T–2	32, 827, 763	6, 401, 414	6, 073, 136	328, 278
Total	68, 797, 616	17, 623, 390	17, 001, 632	621, 758

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NATURAL GAS STORAGE COMPANY OF ILLINOIS, DOCKET NO. CP62-144; NATURAL GAS PIPELINE COMPANY OF AMERICA, DOCKET NO. CP62-145

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 8, 1962)

On December 11, 1961, as supplemented on January 8, 1962, Natural Gas Storage Company of Illinois (Storage) filed in Docket No. CP62-144 an application for a certificate of public convenience and necessity authorizing the acquisition of underground storage rights and the construction and operation of facilities for the evaluation of the characteristics and capabilities of an underground natural gas storage reservoir, described as the Cairo Storage Area, in Louisa County, Iowa, all as more fully set forth in the application as supplemented.

The proposed storage project would be utilized to meet storage requirements of Storage's customers in addition to or supplementary to the service now provided. Authorization to commence the supplementary service will be requested when the capabilities of the reservoir are determined.

Storage estimates the cost of the proposed project to be $2,637,150. Storage presently contemplates financing the project with funds borrowed from The Peoples Gas Light and Coke Company or with funds borrowed from banks. No plan for permanently funding these loans has yet been determined. The application states that Storage desires to reserve the right to make changes in its proposed plan of financing.

Storage proposes to inject approximately 2,800,000 Mcf of gas into the Lower St. Peter formation in the Cairo Storage Area which gas will be purchased from Natural Gas Pipeline Company of America.

On December 11, 1961, Natural Gas Pipeline Company of America (Natural) field in Docket No. CP62-145 an application for a certificate of public convenience and necessity authorizing the construction and operation of a side tap and meter station on its existing transmission facilities in Louisa County, Iowa, and the sale and delivery of approximately 2,800,000 Mcf of natural gas to Natural Gas Storage Company of Illinois.

Natural estimates that the cost of the proposed facilities will be $18,300, which will be financed from funds on hand.

The proposed sale will be made under Natural's FPC Gas Rate Schedule X-1. Natural proposes to make the gas available to Storage during off-peak periods when deliveries to other customers will not be affected and also during other than off-peak periods when gas may be available by reason of curtailment by customers of Natural of their purchase of gas for interruptible sales.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 29, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the applications or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Natural Gas Storage Company of Illinois, an Illinois corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its opinion and order of September 11, 1952, in Docket No. G–1757 (11 FPC 366).

(2) Applicant, Natural Gas Pipeline Company of America, a Delaware corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 13, 1942, in Docket No. G–235 (3 FPC 830).

(3) The facilities hereinbefore described, as more fully described in the respective applications, as supplemented, in this proceeding, will be used in the transportation and sale of natural gas in interstate commerce subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicants are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) Applicants are able and willing properly to do the act and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(5) The proposed construction and operation of facilities are required by the public convenience and necessity, and certificates therefor should be issued as hereinafter ordered and conditiond.

(6) Public convenience and necessity require that the certificates issued hereinafter and the rights granted thereunder be conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of said Regulations.

(7) The time within which the facilities authorized in Docket No. CP62–145 should be completed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act should be fixed at 90 days from the date on which this order issues.

(8) Applicant in Docket No. CP62–145 should be permitted to sell and deliver natural gas to Natural Gas Storage Company of Illinois under the authorization hereinafter granted until December 31, 1963, and said sale should be limited to 2,800,000 Mcf of gas.

(9) The maximum inventory of gas stored in the Cairo Storage Area should be limited to 2,800,000 Mcf of 1,000 Btu gas at 14.65 psia.

(10) Applicant in Docket No. CP62–144 should submit monthly reports containing the following information on the proposed testing operations:

(a) The volumes of natural gas injected or withdrawn together with the corresponding total volumes in the reservoir;

(b) The maximum daily injection or withdrawal rate experienced during the month;

(c) The average working pressure on such maximum days taken at a central measuring point where the total volumes injected or withdrawn is measured;

(d) The water level in each observation well;

(e) The stabilized shut-in wellhead pressure of each observation and active well when pressure stabilization exists. A graph shall accompany the report showing the injection and withdrawal rates by days, the water levels, and stabilized shut-in wellhead pressures for each observation well by days;

(f) All gamma ray, neutron, or other electric log surveys;

(g) All core analyses;

(h) For each well the date on which gas was first noted during injection and the date on which water seriously encroached during withdrawal;

(i) A map showing the latest concept of structure based on development and the pressures requested in (e) above shall be shown when taken together with the area occupied by the gas bubble, as indicated by the information requested in (h) above;

(j) Status of acreage control for storage purposes;

(k) Status of permits required by State agencies having jurisdiction;

(l) Back pressure data and curves;

(m) Discussion of current operations and conclusions with respect to input capacity of various inventories, input pressure at wells and the ability of the storage reservoir to retain gas; and

(n) Any other data which may aid the Commission in the evaluation of the Cairo Storage project.

(11) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Certificates of public convenience and necessity be and the same are hereby issued authorizing the respective Applicants to construct and operate the facilities hereinbefore described, as more fully described in the applications and supplement in this proceeding, upon the terms and conditions of this order.

(B) The certificates issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of said Regulations.

(C) The time within which the facilities authorized in Docket No. CP62–145 shall be completed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act is hereby fixed at 90 days from the date on which this order issues.

(D) Applicant in Docket No. CP62–145 is hereby permitted to sell and deliver natural gas to Natural Gas Storage Company of Illinois under the authorization granted in paragraph (A) above until December 31, 1963, and said sale is hereby limited to a maximum of 2,800,000 Mcf of gas.

(E) The maximum inventory of gas stored in the Cairo Storage Area is hereby limited to 2,800,000 Mcf of 1,000 Btu gas at 14.65 psia.

(F) Applicant in Docket No. CP62–144 shall submit monthly reports containing the following information on the proposed testing operations:

(a) The volumes of natural gas injected or withdrawn together wtih the corresponding total volumes in the reservoir;

(b) The maximum daily injection or withdrawal rate experienced during the month;

(c) The average working pressure on such maximum days taken at a central measuring point where the total volume injected or withdrawn is measured;

(d) The water level in each observation well;

(e) The stabilized shut-in wellhead pressure of each observation and active well when pressure stabilization exists. A graph shall accompany the report showing the injection and withdrawal rates by days, the water levels, and the stabilized shut-in wellhead pressures for each observation well by days;

(f) All gamma ray, neutron, or other electric log surveys;

(g) All core analyses;

(h) For each well the date on which gas was first noted during injection and the date on which water seriously encroached during withdrawal;

(i) A map showing the latest concept of structure based on development and the pressure requested in (e) above shall be shown when taken together with the area occupied by the gas bubble, as indicated by the information requested in (b) above;

(j) Status of acreage control for storage purposes;

(k) Status of permits required by State agencies having jurisdiction;

(l) Back pressure data and curves;

(m) Discussion of current operations and conclusions with respect to input capacity at various inventories, input pressure at wells, and the ability of the storage reservoir to retain gas; and

(n) Any other data which may aid the Commission in the evaluation of the Cairo Storage project.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NATURAL GAS PIPELINE COMPANY OF AMERICA
DOCKET NO. CP62-162

FINDING AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 8, 1962)

On January 8, 1962, as supplemented on January 26, 1962, and April 24, 1962, Natural Gas Pipeline Company of America (Applicant) filed in Docket No. CP62-162 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction of certain unspecified "budget-type" facilities during the calendar year 1962 at a total cost not to exceed $132,000, with no single project to exceed a cost of $20,000, and the operation thereof for the delivery of natural gas to existing customers, all as more fully set forth in the application, as supplemented.

No increase over presently authorized volumes is requested. Applicant proposes the establishment of additional delivery points to enable existing customrs to provide gas service in areas heretofore without such service. The proposed service would be subject to the following conditions:

(1) Applicant's customers proposing service through the new facilities will not require an increase in their contract volumes presently available from Applicant.

(2) The service will be in an area not heretofore served with natural gas.

(3) Applicant' customers proposing service will have obtained such authorization therefor as may be required.

(4) The estimated peak day delivery requirement in the first and third years of operation for the new area or areas will be less than two and five percent, respectively, of the total peak day supply of natural gas available from Applicant and its affiliate, Natural Gas Storage Company of Illinois, to the customers proposing such service, or 5,000 Mcf, whichever is less.

(5) Applicant's customers proposing the service do not propose to serve any industrial consumers in the new area that would use in excess of 10,000 Mcf of gas per month.

Applicant has not requested any change in the design or operation of its pipeline system or in the rates now charged by it by reason of the construction and operation of the facilities proposed in the subject application.

The subject facilities will be financed from funds on hand.

There is no question as to gas supply.

Pursuant to due notice, a public hearing was held in Washington, D. C., on May 29, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application has been received. A petition to intervene was filed on March 30, 1962, by the coal interests[1] and was withdrawn on April 24, 1962. Staff counsel moved orally at the hearing that that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Natural Gas Pipeline Company of America, a Delaware Corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 13, 1942, in Docket No. G–235 (3 FPC 830).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are prposed to be used in the transportation and delivery of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provision of the Natural Gas Act and the requirements, rules. and regulations of the Commission thereunder.

(4) The construction during the calendar year 1962 of facilities and the operation thereof for the delivery of natural gas to existing customers to serve new areas as proposed by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before March 1, 1963, a statement under oath showing by project: (a) a description of the project or projects constructed pursuant to the authorization hereinfater granted, (b) the location of said project or projects, (c) the names of resale customers served through the operation of the subject facilities, (d) the new areas served by the subject facilities, (e) the actual final cost of the facilities built under the authorization hereinafter granted, and (f) the estimated annual and peak day requirements of the new areas in the third year of operation.

(6) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(7) The authorization hereinafter granted should be limited to construction during the calendar year 1962, and the total expenditures for facilities authorized to be constructed thereunder should be limited to a maximum of $132,000, with no single project to exceed a cost of $20,000.

[1] Fuels Research Council, Inc.; National Coal Association; United Mine Workers of America; Mid-West Coal Producers Institute, Inc.

(8) The certificate hereinafter granted should be subject to the following Conditions:

(a) Applicant's customer or customers proposing service in the new area will not require an increase in the contract volume presently available from Applicant.

(b) The service will be in an area not heretofore served with natural gas.

(c) Applicant's customer or customers proposing service will have obtained such authorization therefor as may be required.

(d) The estimated peak day delivery requirement in the first and third years of operation for the new area or areas will be less than two and five percent, rspectively, of the total peak day supply of natural gas available from Applicant and its affiliate, Natural Gas Storage Company of Illinois, to the customers proposing such service, or 5,000 Mcf, whichever is less.

(e) Applicant's customers proposing the service do not propose to serve any industrial consumers in the new area that would use in excess of 10,000 Mcf of gas per month.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of its Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Natural Gas Pipeline Company of America to construct during the calendar year 1962 the proposed facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, and to operate such facilities only for delivery of natural gas to existing customers for service in new areas as proposed by Applicant.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) Applicant shall submit, on or before March 1, 1963, a statement under oath showing by projects: (a) a description of the project or projects constructed pursuant to the authorization granted in paragraph (A) above, (b) the location of said project or projects, (c) the names of the resale customers served through the operation of the subject facilities, (d) the new areas served by the subject facilities, (e) the actual final costs of the facilities built under the authorization hereinbefore granted, and (f) the estimated annual and peak day requirements of the new areas in the third year of operation.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed thereunder are hereby limited to a maximum of $132,000, with no single project to exceed a cost of $20,000.

(E) The certificate issued by paragraph (A) above is subject to the following conditions:

(a) Applicant's customer or customers proposing service in the new area will not require an increase in the contract volume presently available from Applicant.

(b) The service will be in an area not heretofore served with natural gas.

(c) Applicant's customer or customers proposing service will have obtained such authorization therefor as may be required.

(d) The estimated peak day delivery requirement in the first and third years of operation for the new area or areas will be less than two and five percent, respectively, of the total peak day supply of natural gas available from Applicant and its affiliate, Natural Gas Storage Company of Illinois, to the customers proposing such service, or 5,000 Mcf, whichever is less.

(e) Applicant's customers proposing the service do not propose to serve any industrial consumers in the new area that would use in excess of 10,000 Mcf of gas per month.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP62-207

FINDINGS AND ORDER PERMITTING AND APPROVING ABANDONMENT OF FACILITIES

(Issued June 8, 1962)

On March 2, 1962, Northern Natural Gas Company (Applicant) filed in Docket No. CP62-207 an application pursuant to Section 7(b) of the Natural Gas Act for permission and approval to abandon in place 35.1 miles of 18-inch pipeline east of its Otis compressor facilities in Barton and Ellsworth Counties, Kansas, all as more fully set forth in the application.

The Otis gas field which the subject facilities served is depleted and Applicant therefore has no further use for the pipeline. Service to certain farm tap customers from this pipeline will be abandoned.

The subject facilities were authorized by Applicant's "grandfather certificate" issued in Docket No. G-280.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 31, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Northern Natural Gas Company, a Delaware corporation having its principal place of business in Omaha, Nebraska, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G-280 (3 FPC 967).

(2) The facilities proposed to be abandoned as hereinbefore described and as more fully described in the application in this proceeding, are subject to the jurisdiction of the Commission, and abandonment of such facilities is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(3) Such abandonment of Applicant is permitted by the public convenience and necessity, and an order permitting and approving same should be issued as hereinafter ordered.

(4) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1:30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Permission for an approval of the abandonment by Applicant of the facilities hereinbefore described, as more fully described in the application in this proceeding, be and the same is hereby granted.

(B) Applicant shall advise the Commission of the date of the abandonment within 10 days thereof.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NORTHERN NATURAL GAS COMPANY, DOCKET NO. CP62-210

FINDINGS AND ORDER PERMITTING AND APPROVING ABANDONMENT

(Issued June 8, 1962)

On March 8, 1962, Northern Natural Gas Company (Applicant) filed in Docket No. CP62-210 an application pursuant to Section 7 (b) of the Natural Gas Act for permission and approval to abandon four 1,320 horsepower compressor units at its Pembrook Station located in Upton County, Texas, all as more fully set forth in the application.

It appears that due to a decline in the volumes of gas delivered at the Pembrook Station, the subject four 1,320 horsepower units can be removed and relocated at Applicant's proposed Eunice Compressor Station in Lea County, New Mexico (Docket No. CP61-186). Applicant states that no sales or services will be abandoned and that the relocation of the four units will avoid an expenditure of approximately $600,000 in new equipment at the Eunice Station.

The subject four compressor units were originally certificated by the Commission's order accompanying Opinion No. 249 issued on May 1, 1953, in Docket No. G-1928, *et al.*, 12 FPC 85.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 31, 1962, respecting the matters involved in and the issues presented by the application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Northern Natural Gas Company, a Delaware corporation having its principal place of business in Omaha, Nebraska, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of April 6, 1943, in Docket No. G-280 (3 FPC 967).

(2) The facilities to be abandoned, as hereinbefore described and as more fully described in the application in this proceeding, are subject to the jurisdiction of the Commission, and abandonment of such facilities is subject to the requirements of Subsection (b) of Section 7 of the Natural Gas Act.

(3) Such abandonment by Applicant is permitted by the public convenience and necessity, and an order permitting and approving same should be issued as hereinafter ordered.

(4) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Permission for and approval of the abandonment by Northern Natural Gas Company of the facilities hereinbefore described, and as more fully described in the application in this proceeding, be and the same is hereby granted.

(B) Applicant shall advise the Commission of the date of the removal of the equipment within ten days after completion thereof.

EL PASO NATURAL GAS COMPANY, DOCKET NO. CP60-72; PAN AMERICAN PETROLEUM CORPORATION, G-19277; HUMBLE OIL & REFINING COMPANY, CI60-65 AND CI60-66; BELCO PETROLEUM CORPORATION, CI61-475; BENEFICIAL OIL COMPANY, CI61-729

OPINION AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 11, 1962)

*Syllabus**

1. To accept producers' contract price on theory advanced by them—based upon economic evidence—would be tantamount to abdication of Commission's regulatory responsibility under the Natural Gas Act. P. 1137.
2. To preside over rising spiral of prices as dictated by competition in open market and trends associated therewith, would be to forego regulation of producer prices in public interest, and be inconsistent with "real administrative effort to hold back prices" demanded of Commission by CATCO. P. 1137.
3. Evidence presented by producers offers no substantial, let alone compelling, proof of public's need to have gas supplies certificated at proposed contract price, or any initial price in excess of in line price of 15.384-cents. P. 1138.
4. Value of trend evidence discussed; Commission *finds* no evidence which compels a finding that producers' initial contract price is required by public convenience and necessity; *concludes* certificates should be conditioned upon filing of initial price not in excess of in line area price of 15.384-cents. P. 1138.
5. Absent a finding of its liability to perform, Pan American's certificate application is *denied* and temporary authorization rescinded. P. 1138.
6. Commission *states* that *Glassell* Case in no way bears upon use of trend evidence in either rate or certificate proceeding for purpose of justifying rates on some basis other than traditional rate base cost of service approach. P. 1139.
7. Commission *issues* certificates of public convenience and necessity under Section 7 of the Natural Gas Act. P. 1140.

Allen R. Grambling, George D. Hornnig, Jr., and *John J. Curtin, Jr.* for El Paso Natural Gas Company.

John F. Jones, Harold H. Young, Jr., Clifford O. Stone, Jr., and *William J. Grove* for Pan American Petroleum Corporation.

William J. Merrill and *George H. Lawrence* for Humble Oil & Refining Company.

Roy J. Voegeli and *J. Evans Attwell* for Belco Petroleum Corporation.

William M. Bennet, J. Calvin Simpson, and *Walter G. Linstedt* for People of the State of California and Public Utilities Commission of the State of California.

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* Designated Commission opinion No. 358. Initial decision appears on page 1140.

Harry P. Letton, Jr., Henry F. Lippitt, 2d, Milford Springer, Robert M. Olson, Jr., J. David Mann, Jr. William W. Ross, John E. Holtzinger, Jr., and *William E. Zeiter* for Southern California Gas Company and Southern Counties Gas Company of California.

F. T. Searls, Malcolm H. Furbush, and *John B. Gibson* for Pacific Gas & Electric Company.

Richard C. Steffey for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

Ross, *Commissioner:*

This is a certificate proceeding under Section 7 of the Natural Gas Act. Applicants Humble Oil & Refining Company, Belco Petroleum Corporation, Beneficial Oil Company, and Pan American Petroleum Corporation seek certificates of public convenience and necessity for the sale of natural gas from various units in the Tip Top-Hogsback Field of the Big Piney area of Sublette and Lincoln Counties in southwestern Wyoming to El Paso Natural Gas Company. El Paso seeks a certificate for the construction of 13.1 miles of pipeline and related metering and dehydration equipment at an estimated cost of $449,000 to connect its existing Big Piney lateral to the producers' wells. Gas taken into El Paso's main line from the Big Piney lateral flows north and west to markets served by El Paso in the Pacific Northwest. The gas dedicated to El Paso under its contracts with the producers in this case is gas-well gas produced from the Muddy and Frontier formations at depths ranging from 7500 to 8000 feet. The total of original reserves dedicated under the contracts is estimated to be in excess of 240 million Mcf.

The initial contract price proposed by the producers is 17.5 cents per Mcf at 15.025 psia for gas delivered at 500 pounds pressure (gauge) plus an additional one cent per Mcf for gas which is capable of being delivered into an 860 pound gathering system. The contracts also provide for periodic increases of one cent per Mcf every five years during the 20-year term of the contracts, as well as for renegotiations of a reasonable market price every five years.[1] At the end of ten years, the minimum pressure requirement becomes 250 pounds and the provision for an additional one cent per Mcf for 860 pound gas expires; provided, however, that El Paso agrees to continue payment of the additional one cent if it is being paid at the end of the ten-year period. The contracts contemplate the installation of wellhead separators by the producers, and delivery to El Paso at the wellmouth or at the outlet of the separators, as the case may be. The gas thereafter is to be transported by El Paso to its Opal processing plant, and El Paso agrees to pay the producers 30 percent of its "net realization f.o.b. the plant for liquids saved and sold". The contracts contain no upward Btu adjustment provisions, but do provide for a percentage reduction in price if El Paso elects to take gas below the minimum Btu content prescribed. There is no provision for reimbursement of current taxes. El Paso, however, is required to reimburse the producers for 75 percent of any new or increased taxes, except *ad valorem* taxes on properties and net income taxes,

[1] Under Section 154.93 of the Commission's Regulations under the Natural Gas Act, as amended effective April 3, 1961, and April 2, 1962, this renegotiation provision would be inoperative and of no effect as part of applicants' rate schedules if their contracts were executed on or after April 3, 1961, and the contracts themselves would be rejected as rate schedules if the contracts with this provision were executed on or after April 2, 1962. Inasmuch as the contracts in this case were executed prior to April 3, 1961, the renegotiation provision is here allowed, although contrary to present Commission policy; and its allowance is not to be construed as a waiver or exception to that policy.

imposed after the execution of the contracts. The contracts provide for El Paso to take or pay for 75 percent of the aggregate daily stabilized producing capacity of the producers' wells, and in the case of Belco, not more than one Mcf for each 10,000 Mcf of dedicated reserves.

Pending determination of their applications in this proceeding, temporary authorizations were issued to each of the applicants upon request. In authorizing the producers to commence deliveries to El Paso on a temporary basis, the Commission conditioned the initial price to be charged to 15 cents per Mcf at 14.65 psia (15.384 cents per Mcf at 15.025 psia), the Wyoming Area ceiling level for new contracts as set forth in the Commission's *Statement of General Policy No. 61–1*, issued September 28, 1960, 24 FPC 818. Gas is now being sold to El Paso in accordance with the temporary authorizations as so conditioned.

On August 25, 1961, the hearing examiner presiding in this proceeding issued an initial decision granting permanent certificates of the public convenience and necessity to El Paso and to Humble, Belco and Beneficial, but conditioning the producer certificates upon the filing of an initial price of 15 cents per Mcf at 14.65 psia in lieu of the proposed contract price of 18.5 cents per Mcf at 15.025 psia (17.5 cents plus one cent for gas delivered at 860 pounds pressure). The conditioned certificate price of 15 cents would apply to gas delivered either at 500 pounds pressure or at 860 pounds pressure. The examiner dismissed Pan American's application and rescinded its temporary authorization to sell to El Paso for want of a showing of its ability to perform. Subsequent to the filing of the applications in this proceeding, Pan American transferred all of its interest in the producing formations involved to Belco, retaining only its interest in certain shallow formations from which no gas is now being produced, or is contemplated to be produced, and with respect to which Pan American has no installed facilities for the delivery of gas to El Paso. In the absence of a finding that Pan American is able and willing to do the acts and perform the services proposed, as required by Section 7 of the Act, the examiner rejected Pan American's claim to a certificate.

Exceptions to the examiner's initial decision were filed by the producers and by the intervening Southern California Gas Company and Southern Counties Gas Company of California. In substance, and insofar as they are material, these exceptions take issue with the price condition imposed by the examiner on the certificates issued to Humble, Belco and Bneficial, and with the denial of a certificate to Pan American. Upon review of the record in this proceeding. the parties' briefs and their exceptions to the examiner's decision, we are of the opinion that the examiner's findings and order are correct.

As noted above, the initial price ceiling for the Wyoming Area, set forth in *Statement of General Policy No. 61–1*, is 15 cents per Mcf at 14.65 psia, or 15.384 cents per Mcf at 15.025 psia. This ceiling represents an administrative judgment of the initial price line which the courts have admonished this Commission to hold in certificate proceedings under Section 7 in order that the consuming public may be protected until just and reasonable prices can be determined in normal adjudicatory rate proceedings under Section 4 or Section 5 of the Act.[2] The appropriateness of the ceiling level set by the Commission for Wyoming is confirmed by the evidence in this case. The record shows that an estimated 58 million Mcf of gas is being sold annually in Wyoming under 36 contracts with permanently certificated initial prices of 10 cents per Mcf and above

[2] *Atlantic Refining Co.* v *Public Service Commission* ("CATCO"), 360 U.S. 378; *United Gas Improvement Co.* v *F.P.C.*, 283 F. 2d 817 (CA9), *cert.* denied 365 U.S. 881; *Public Service Commission* v. *F.P.C.*, 287 F. 2d 146 (CADC), *cert.* denied, 365 U.S. 880; *United Gas Improvement Co.* v. *F.P.C.*, 287 6. 2d 159 (CA10); *United Gas Improvement Co.* v. *F.P.C.*, 290 F. 2d 133 (CA5).

(15.025 psia). Some 40 million Mcf of this amount is sold under 10 contracts at 15 cents, and some 6 million Mcf is sold under 5 contracts at 15.384 cents. The remaining contracts involve sales of lessor amounts at 10 cents, 11 cents, 11.65 cnets and 12 cents. The most recently certificated sales are those at 15.384 cents. This price level was established by the Commission in *Humble Oil & Refining Co., et al.*, 24 FPC 191 (August 9, 1960), a case involving three of the producer applicants in the instant proceeding and the sale of gas from some of the same units and subject to the same conditions of production and operation as are found in the present case. In the *Humble* case, the Commission found that the proposed price of 16 cents per Mcf for gas delivered to El Paso at 860 pounds pressure was higher than required by the public convenience and necessity, and the certificates issued were conditioned upon the filing of a price of 15.384 cents per Mcf. Clearly this price, as shown on this record, as found by the examiner, and as reflected by the Commission's policy statement are ceiling, represents the price line to be held by the Commission in this case in the absence of compelling evidence to show that a higher price is required by the public convenience and necessity.

To justify their proposed contract price in this proceeding, the producers have presented an economic study which purports to show the reasonable financial requirements of the industry. This economic evidence consists of charts and tables setting forth certain supply, demand, cost, revenue, and market price trends based on data compiled from the Census of Mineral Industries, United States Bureau of Mines, Mineral year book, and various trade publications for (1) the entire United States; (2) the States of Colorado, Montana, Utah and Wyoming; (3) the States of Kansas, New Mexico, Oklahoma, and Texas; and (4) a combination of the eight named western states.

The producers' witness, in presenting the foregoing evidence, stated that costs incurred by the producers for the specific supplies committed to El Paso in this proceeding are meaningless for the purpose of testing the appropriateness of the initial price, and that the appropriate price must be determined on the basis of the financial requirements of the industry as related to certain trends on an area basis. In his opinion, however, industry revenue requirements cannot be related to area prices except through the mechanics of the competitive market system. Thus the producers take the position that because the trends presented show a decline in productivity per foot drilled, an increase in cost of production, and a decline in the ratio of new supply to net production, present gas prices are not high enough to furnish producers with the incentive to find, develop, produce and market sufficient quantities of gas to meet consumer demand; and that prices should be allowed to increase until they are high enough to bring forth the supplies needed to equal demand and the foregoing trends are reversed.

Under the theory advanced by the producers, the economic evidence presented could be used to justify any price which might be thought to be required as an incentive to bring adequate supplies of new gas to the interstate market, and which has been negotiated at arms length in a competitive market. To accept the producers' contract price on this theory of regulation would be tantamount to an abdication of our regulatory responsibility under the Natural Gas Act. As stated by the Court of Appeals for the Fifth Circuit in *U.G.I.* v. *F.P.C.*, *supra*, ". . . the only justification for giving the Commission the duty to regulate prices was the determination by Congress that the producers have a supply that is so restricted in relation to demand that they have the economic power to bargain for prices that will be injurious to the public." To preside over a rising spiral of prices as dictated by competition in the open market and the trends associated with that market is to forego regulation of producer prices in the public interest,

and would hardly be consistent with that "real administrative effort to hold back prices" which the Supreme Court of the United States has demanded of us. See *P.S.C.* v. *F.P.C., supra.*

The evidence presented by the producers in this proceeding offers no substantial, let alone compelling, proof of the public's need to have the gas supplies here involved certificated for sale at the proposed contract price, or any initial price in excess of the in-line price of 15.384 cents per Mcf. The evidence does not show that the 15.384-cent price is inadequate to stimulate continued exploration and development of new reserves in Wyoming. The trends portrayed in the economic study presented by the producers do not necessarily bespeak the necessity for us to provide an increased incentive for exploration and development in the Wyoming Area or more particularly in the Green River Basin of southwest Wyoming where the gas in this case is being produced. As noted before, the gas purchased by El Paso in southwest Wyoming is delivered to markets served by its Pacific Northwest pipeline. However, no evidence as to the demand for gas in these markets has been presented, nor is there a showing that the development of new reserves to serve these markets is not progressing at a rate sufficient to meet the present or future needs of the area. On the other hand there is evidence to show that price levels in the four Mountain States have been adequate consistently to call forth new reserves which are more than double the production of the region; and that El Paso is apparently satisfied that exploration in this area is going along as well as can be expected.

With respect to the use of trend evidence, it is impossible to draw any easy conclusions as to what particular trends may mean in terms of price. Thus a trend which shows reserves increasing at a declining rate in relation to the demand for gas does not require a conclusion that there is insufficient price incentive and profit potential. Exploration and development may well be continuing at a reasonable pace, even though the discovery of new reserves may appear to lag behind the demand for additional gas. Furthermore, any judgment with respect to the rate of exploration and development since 1954, as indicated by historical trends, must be tempered by the understanding that such trends reflect in some degree past uncertainty among producers as to the course which producer regulation would take after the Supreme Court's decision in the Phillips case.[2]

The trend evidence presented by the producers in this proceeding is not sufficient to permit us to draw any conclusions therefrom with respect to the initial contract price here proposed. Without some substantial proof of how this general economic data, applicable to the industry as a whole over wide geographical areas, can be related to and utilized in support of the specific price proposed for these sales in this particular area, such evidence has no real probative value. There is no evidence in the record before us which compels a finding on our part that the producers' initial contract price is required by the public convenience and necessity; and, we conclude, as did the examiner, that the certificates herein issued should be conditioned upon the filing of an initial price not in excess of the in-line area price of 15.384 cents per Mcf, as reflected in the ceiling level for the Wyoming Area established by the Commission's *Statement of General Policy No. 61–1.*

With respect to Pan American's application, we agree with the finding of the examiner that Pan American has rendered itself unable to perform the services for which it seeks a certificate by reason of the transfer of its producing properties to Belco. In the absence of a finding of its ability to perform, Pan American's certificate application must be denied and the temporary authorization

[2] *Phillips Petroleum Co.* v. *Wisconsin,* 347 U.S. 672.

heretofore issued must be rescinded. Such other issues as have been presented, are properly disposed of in the examiner's decision; and to the extent that his decision with respect to these issues, as well as the issues heretofore discussed, is consistent with this opinion and order, we adopt his decision as our own. We would note, however, that the examiner erred in referring to and citing our decision in *Alfred C. Glassell, Jr., et al.*, 25 FPC 1071. This case does not stand for the proposition that trend evidence is unacceptable in producer rate proceedings under Sections 4 and 5, as indicated by the examiner. As the language cited by the examiner shows, the issue there considered was whether the Commission should depart from long established original cost concepts in determining the rate base of natural-gas companies, or should use trended costs or reproduction costs for that purpose. This discussion of rate base is wholly within the context of a cost of service approach to the determination of just and reasonable rates, and relates to the computation of a proper return to be included in the cost of service. The *Glassell* case in no way bears upon the use of trend evidence in either rate proceedings or certificate proceedings for the purpose of justifying rates on some basis other than the traditional rate base cost of service approach.

The Commission further finds:

(1) El Paso is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission.

(2) El Paso's proposed facilities hereinabove referred to, and more fully described in its application, will be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission; and such facilities, together with the construction and operation thereof, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Humble, Belco, and Beneficial, independent producers of natural gas, are now, or upon initiation of the proposed sales to El Paso will be, "natural-gas companies" within the meaning of the Natural Gas Act, and are, or will be, engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission.

(4) The sales of natural gas proposed by Humble, Belco, and Beneficial, hereinabove referred to, and more fully described in their applications, are subject to the jurisdiction of the Commission, and such sales, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefore ,are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) Subject to the requirements of our order herein and the conditions attached to the certificates herein issued, El Paso, Humble, Belco, and Beneficial are able and willing properly to do the acts and to perform the services proposed, and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(6) The construction and operation of the facilities proposed by El Paso, and the sales proposed by Humble, Belco, and Beneficial, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity upon the conditions hereinafter set forth, and certificates should be issued to each of them as ordered below.

(7) The application for a certificate of public convenience and necessity filed by Pan American should be dismissed, and the temporary authority heretofore granted should be rescinded.

(8) The conditions attached to the certificates herein issued are required by the public convenience and necessity.

(9) Except as herein granted, the exceptions to the examiner's decision should be denied.

The Commission orders:

(A) Certificates of public convenience and necessity are hereby issued, upon the conditions hereinafter set forth, to El Paso for the construction and operation of the facilities proposed, as more fully described above and in its application; and to Humble, Belco, and Beneficial for the sale of natural gas in interstate commerce for resale as proposed, and for the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, as more fully described above and in their applications.

(B) The certificates herein issued to Humble, Belco, and Beneficial are granted upon the express condition that the initial price for the proposed sale of gas to El Paso shall not be in excess of 15 cents per Mcf at 14.65 psia (15.384 cents per Mcf at 15.025 psia), and that said producer applicants shall file supplements to their presently filed rate schedules reflecting the conditioned price as their initial price in lieu of the initial price provided in their contracts with El Paso. The initial price as so conditoned and made a part of the producers' filed rate schedules shall be applicable to all of the gas delivered to El Paso under the certificates herein issued regardless of delivery pressure.

(C) The certificates herein issued, and the rights granted thereunder, are conditioned upon compliance by the applicants with all applicable Commission Regulations under the Natural Gas Act and are without prejudice to any action the Commission may determine to be necessary or appropriate as a result of the outcome of *United States* v. *El Paso Natural Gas Company and Pacific Northwest Pipeline Corporation*, Civil No. 143-57 (D. Utah).

(D) The certificates herein issued are not transferable and shall be effective only so long as each of the applicants continues the acts and operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations and orders of the Commission.

(E) The grant of the certificates herein shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act, or of Part 154 of the Regulations thereunder. Such grant is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicants. Further, the action in this proceeding shall not foreclose nor prejudice any further proceedings or objection relating to the operation of any price or related provision in the gas purchase contracts herein involved.

(F) The application for a certificate of public convenience and necessity filed by Pan American is hereby denied, and the temporary authorization thereunder heretofore issued to Pan American is hereby rescinded.

(G) Except as herein granted, the exceptions to the examiner's decision are hereby denied.

DECISION

UPON APPLICATION FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY PURSUANT TO SECTION 7(c) OF THE NATURAL GAS ACT

(Issued August 25, 1961)

KURTZ, *Presiding Examiner:* These proceedings involve applications for certificates of public convenience and necessity filed pursuant to Section 7(c) of the Natural Gas Act. Pan American Petroleum Corporation (Pan American),

Humble Oil & Refining Company (Humble), Belco Petroleum Corporation (Belco), and Beneficial Oil Company (Beneficial), hereinafter sometimes referred to as producers, seek permanent certificates to sell to El Paso Natural Gas Company (El Paso) natural gas produced from certain acreage in Sublette and Lincoln Counties, Wyoming, at an initial maximum price of 18½ cents per Mcf, at a pressure of 15.025 psia, as set forth in gas purchase contracts between the parties. El Paso in turn seeks a permanent certificate to construct and operate facilities necessary to the purchase of this natural gas for transportation and resale to its existing markets.

Pending determination of the applications, temporary certificates for the authorization as requested in the above applications have been issued to all of the applicants on a condition that the initial rate to be charged El Paso by the producers shall not exceed 15 cents per Mcf at a pressure of 14.65 psia (15.384 cents at 15.025 psia) for gas delivered. Each of the above producers has signified its acceptance of the rate condition as set forth in the temporary certificates issued for deliveries of gas that are now being made to El Paso.[1]

Intervening in these proceedings are: the People of the State of California and the Public Utilities Commission of the State of California (State of California); the Pacific Gas & Electric Company (PG&E); and the Southern California Gas Company and Southern Counties Gas Company of California (Southern California), hereinafter sometimes referred to as interveners. The interest of these interveners relates to the rate proposed to be charged by the producers for natural gas to be sold to El Paso.

The interveners and staff counsel urge that the maximum initial rate to be charged by the producers for natural gas sold to El Paso should not exceed 15 cents per Mcf at a pressure base of 14.65 psia. Also, the staff contends that the application of Pan American should be dismissed and the temporary certificate issued to this applicant be rescinded. This is concurred in by the State of California, which, in addition, contends that the provision in the contracts providing for renegotiation of the rate to be charged should be deleted therefrom. Southern California, while contending that the maximum rate should be 15 cents per Mcf at 14.65 psia, suggests that the more appropriate price would be 15 cents at 15.025 psia, and that the initial price so established be fixed as the base from which each of the several one cent escalations is to be computed.

The above applications were consolidated for hearing, and all parties, with the exception of Beneficial, participated therein. Staff counsel, and all parties, with the exception of Beneficial, filed briefs in support of their respective positions.

El Paso, a Delaware corporation, owns and operates an integrated pipeline system extending from Canada to Mexico, which is located in the States of Washington, Oregon, Idaho, Wyoming, Utah, Colorado, Arizona, New Mexico, and Texas. Its overall system requirements for natural gas are in excess of an average of 3½ billion cubic feet per day. In furtherance of this service,

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[1] Temporary certificates were issued on November 25, 1960, pursuant to requests by: El Paso in Docket No. CP60–72 on October 12, 1960; Belco Petroleum in Docket No. C160–475 on October 11, 1960; Humble in Docket Nos. C160–65 and C160–66 on October 17, 1960, and October 20, 1960, respectively; Pan American in Docket No. G–19277 on October 31, 1960; and Beneficial in Dock No. C161–729 on November 7, 1960. Belco, on March 8, 1961, filed in Docket No. C160–475 an amendment to its application, requesting temporary certificate to make sales to El Paso from additional acreage dedicated to El Paso, such acreage having been acquired from Pan American, effective as of January 1, 1961, which temporary certificate was issued on May 19, 1961.

El Paso and its subsidiary Pacific Northwest Pipeline Corporation[2] entered into the contracts here under consideration with the producers. These contracts add an additional 240 billion cubic feet of natural gas to El Paso's claimed gas reserves at the end of 1960 of 37.7 trillion cubic feet. Under these contracts, El Paso estimates that it will purchase at this time an average of 3 to 4 million cubic feet of gas per day. The deliverability summary submitted by El Paso disclosed a capability of this acreage to deliver in excess of 25 million cubic feet per day. To secure this gas, El Paso's application discloses the necessary construction of 13.1 miles of pipeline off its existing Green River Basin lateral line to connect 13 wells. These wells are located in various operating units hereinafter named, and the units are within Sublette and Lincoln Counties, Wyoming. The total cost of additional facilities is estimated to be $449,000.

The natural gas herein proposed to be acquired by El Paso is not to be dedicated to any particular sale, class of sale or customer, and is to be used by El Paso in conjunction with its other existing gas supply in meeting system market requirements in respect to both present and future customers. El Paso considers that it has an obligation to make available a market for gas developed along its pipeline system so as to provide the stimulus for additional drilling to secure additional supplies of gas to be available when needed. As of October 12, 1960, El Paso had paid to Belco, under other gas purchase contracts in the Green River Basin, over $6 million for gas which it could not take. El Paso claims that it will be in a position to recoup this gas so as to avoid the penalty of paying for gas not taken.

Humble, a Delaware corporation, filed applications on January 19, 1960, in Docket Nos. CI60–65 and CI60–66, resulting from contracts entered into between Carter Oil Company[3] and Pacific Northwest Pipeline Corporation on August 5, 1959, and August 6, 1959, respectively. The contract of August 5, 1959, was amended by further agreements entered into on August 5, 1959, August 10, 1959, and September 9, 1959. This contract dedicates to El Paso all of the working interest in the natural gas produced from formations down to and including the Muddy Formation underlying 1,011.98 acres in the Green River Basin Unit located in Sublette and Lincoln Counties, Wyoming. The contract of August 6, 1959, was amended by agreements dated August 6, 1959, August 10, 1959, and August 31, 1959, and dedicates to El Paso all of the working interest in natural gas produced from formations down to and including the Muddy Formation underlying 4,058.60 acres in the Figure Four Canyon located in Sublette County, Wyoming, and in this unit Humble is the designated operator. These contracts cover all of Humble's interest in these two units.

Belco, a Delaware corporation, filed an application on April 13, 1960, in Docket No. CI60–475, and an amendment thereto on October 11, 1960, resulting from a contract entered into on December 10, 1959, with Pacific Northwest Pipeline Corporation, which contract was amended on September 30, 1960. This contract dedicates to El Paso a maximum of 300 billion cubic feet of economically recoverable reserves of gas with a maximum delivery of 40,000 Mcf per day from Belco's interest in natural gas underlying about 43,081 acres in

[2] Pursuant to an order by the Commission issued on December 23, 1959, in Docket Nos. G–13018 and G–13019, 22 FPC 1091, a merger was effected by and between Pacific Northwest Pipeline Corporation and El Paso whereby all of the rights, obligations, and responsibilities of Pacific Northwest Pipeline Corporation were merged into and became a part of El Paso, with El Paso being the surviving company.

[3] As of December 31, 1959, a merger was effected by and between the Carter Oil Company and Humble whereby all of the assets, liabilities, and properties of the Carter Oil Company were merged into and became a part of Humble, with Humble being the surviving company.

Sublette and Lincoln Counties, Wyoming, and as to these acres the approximate working interest owned by Belco is as follows: 100% in 24,799 acres; 50% in 6,377 acres; 40% 6,803 acres; 33% in 3,149 acres; and 25% in 1,953 acres. This acreage is located in the Green River Basin Unit, the Figure Four Canyon Unit, the Dry Piney Unit, the Rocking Chair Unit, the Carl-Pat Area, the Connelly Area, the East LaBarge Unit, and the Stead Canyon Unit. In the Stead Canyon Unit, the unitization has been terminated, and each working interest operates its own leases. Belco is the designated operator for the Green River Basin Unit, the Rocking Chair Unit, the Carl-Pat Area, the Connelly Area, and the East LaBarge Unit.

Pan American, a Delaware corporation, filed an application on August 17, 1950, in Docket No. G–19277, resulting from a contract entered into with Pacific Northwest Pipeline Corporation on June 30, 1959, which contract was amended on July 2, 1959, and on December 7, 1960. This contract dedicated to El Paso all of Pan American's share of natural gas within the formations down to and including the Muddy Formation underlying certain acreage in the Green River Basin Unit. At the hearing on this application, Pan American stated that it had agreed with Belco, on or about February 1, 1961, to a trade of assets effective as of January 1, 1961. Out of this transaction Pan American retained a 50 percent working interest in formations underlying the acreage designated in its application in the Green River Basin Unit down to the base of Mesa Verde Formation, and Belco obtained the production rights in the Frontier Formation formerly held by Pan American. The Frontier Formation underlies the Mesa Verde Formation and is the only formation from which gas is currently being produced and sold to El Paso in this unit. Pan American has no facilities to deliver gas from the retained formations, nor does it have an understanding with Belco, the operator of the unit, regarding production from the retained formations. In fact, it is not known when production will commence therefrom. Under such circumstances, the motion made by staff counsel to dismiss the application of Pan American must be granted, as no showing has been made of ability to perform. The necessary findings required under Section 7(e) of the Natural Gas Act cannot be made. The question here does not involve a dedication of land as a part of an overall proposal, but rather the ability to sell gas for which a certificate is requested.

Subsequent to the filing of the staff's and intervener's briefs, Pan American, on June 22, 1961, submitted an amendment to its application in Docket No. G–19277. This amended application purports to make the application conform to the evidence adduced during the hearing as to Pan American's interest in the Green River Basin Unit. Under Section 1.11(b), this filing is not required, nor is it necessary to pass upon the acceptability of this amendment under the disposition here made of Pan American's application.

Beneficial, a Utah corporation, filed an application on November 7, 1960, in Docket No. CI61–729, resulting from a contract for the sale of natural gas to El Paso entered into on October 1, 1960.[4] This contract recites a dedication to El Paso of 15 billion cubic feet of economically recoverable reserves of gas from its 62½ percent interest in the formations down to and including the Muddy Formation underlying 316.13 acres in Section 20 in the Green River Basin Unit and in Section 21 in the East LaBarge Unit. The remaining interest underlying this acreage in the East LaBarge Unit is held by Belco. Beneficial requested that the Commission dispose of its application under the shortened procedure provided for by Section 1.32(b) of the Commission's Rules of Practice and Procedure. This request was not granted. At the hearing Beneficial did

[4] Evidence by reference, Item "O."

not appear in support of its application. However, it did send two letters to the Commission, under dates of February 28, 1961, and March 15, 1961, setting forth its position. In these letters, Beneficial pointed out that it had only a small interest in the total area to be considered at the hearing, and that it was not economically feasible for it to be represented at the hearing, and, further, that it was in general agreement with the other applicants as to the rate to be charged for the gas sold. Staff counsel suggests that, due to the small amount of acreage involved, any determination made as to the applications of Humble and Belco be assumed to apply to Beneficial's application.

As above noted, Beneficial did accept the temporary certificate with a price condition, and this temporary also carried a condition that service, once having been commenced, could not be discontinued without permission of the Commission. Under the particular circumstances surrounding this application, the staff's position is reasonable and should be followed.

The only issue in these proceedings, as recognized by all parties, is the question of the rate to be charged by the producers for gas delivered to El Paso, except for the contention by Pan American that a certificate of public convenience and necessity, should be granted to it. The acreage from which gas is to be delivered, as above-mentioned, lies within Sublette and Lincoln Counties, Wyoming, with the gas delivered to El Paso at or near the wellhead. The going firm price for gas in this area is 15 cents per Mcf at a pressure base of 14.65 psia (15.384 cents at 15.025 psia), as evidenced by the Commission's *Statement of General Policy No. 61–1*, adopted December 30, 1960, 24 FPC 818, and the immediate prior decision of the Commission relating to this area, issued August 9, 1960, in *Humble Oil & Refining Co. et al.*, Docket No. G–13679 *et al.* (24 FPC 191), known as the East LaBarge case. No subsequent firm higher prices for gas are applicable in this area. The provisions applicable to the initial price for gas as set forth in the contracts between El Paso and the producers provide for a price of 17½ cents per Mcf at a pressure base of 15.025 psia (17.0632 cents at 14.65 psia), with an additional one cent if the gas from the wells is initially capable of producing into an 860 pound gathering system, irrespective of the pressures existing in the gathering system. The ability of the wells to so produce is not questioned even though El Paso, for the convenience of its system, is taking the gas at pressures above 500 pounds but lower than 860 pounds. Thus, the initial price here in question is 18½ cents per Mcf. The contracts further provide for the taking of certain volumes with El Paso having the right to regulate the flow of gas at the point of delivery subject to restrictions relating to the ability of the wells to produce and reservoir damage. In addition to the above, the producers will receive 30 percent of El Paso's net realization f.o.b. its Opal plant for liquids extracted from the gas sold. The contracts do not include any so-called favored nation provisions. However, if El Paso does enter into a contract containing such a provision, the Humble contracts are to be so amended. These contracts, in addition to the step increases in price, provide for renegotiation of the price on or before July 1, 1962, to the reasonable market price for gas then delivered, and the price is subject to tax adjustment provisions.

When, as here, the contract price is higher than the going firm price for gas now sold in Sublette and Lincoln Counties, Wyoming, the applicants must justify the proposed price. In *Public Service Commission of New York* v. *Federal Power Commission*, 287 F. 2d 146 (CADC 1960), *cert.* denied 365 U.S. 880, 882, the Court in referring to the *Catco* case, *Atlantic Refining Co.* v. *Public Service Commission*, 360 U.S. 378, pointed out that this decision posed for the Commission two alternative courses in cases where a natural gas company seeks certification of sales at prices which are suspiciously higher than other

or former prices in the area, or which in some way will tend to have an inflationary impact upon the natural gas market. The two courses are the attaching of conditions to protect the public interest while other rate testing procedures are in progress, and the granting of unconditional certification upon evidence sufficient to support a finding of public convenience and necessity. The Court went on to state, at page 150:

> The Catco decision does not prescribe the standard of proof which must be satisfied to support an unconditional certification. Its tenor, however, is unambiguous; the opinion expressly reaffirms that it was 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' *Atlantic Refining Co. v. Public Service Commission, supra*, 360 U.S. at page 388, 79 S.Ct. at page 1253. We believe that the Supreme Court meant to impress upon the Commission an interpretation of the 'public interest' which, in the context of a rising natural gas market, demands a real administrative effort to hold back prices.

No claim is made by the applicants that the going price of 15 cents per Mcf at 14.65 psia is confiscatory. In justification of the contract price, it is alleged that: the contract was entered into at arm's length, the present price is not out of line because increases have occurred in costs associated with the drilling and operation of wells, the benefits to El Paso of gas delivered at 860 pounds pressure justifies an additional one cent per Mcf over gas delivered at 500 pounds pressure, the contract price is lower than the prices paid for gas by El Paso from other sources, particularly from Colorado Interstate Gas Company, the 18½ cent price will not trigger any other gas purchase contracts of El Paso, the contract price in itself will not cause an increase in El Paso's rates, and the higher price is necessary to stimulate exploration and development.

Attention is called to the applicants' contention that these prices will not trigger the price of gas in any of El Paso's gas purchase contracts under so-called favored nation provisions. In these proceedings, El Paso's contract with Beneficial and Belco does include acreage in the East LaBarge Unit, which unit lies adjacent to the Green River Bend Unit and the Figure Four Canyon Unit. These units are within the same gas field and the production therefrom is from a common formation known as the Frontier Sand. As noted in the decision granting certificates of public convenience and necessity to Humble, Pan American, and Belco to sell gas to El Paso from the East LaBarge Unit, the contract between El Paso and Pan American therein referred to does contain a favored nation clause, operative as to the East LaBarge Unit.[5] (24 FPC 198.)

The above contentions have been heretofore advanced by these same applicants in the above-mentioned East LaBarge case, involving the sale of gas to El Paso from the same area. The Commission held in that proceeding that the applicants El Paso, Humble, Pan American, and Belco had not justified the contract price and conditioned such price to 15 cents per Mcf at 14.65 psia. With the exception of additional evidence being introduced in support of the claim that higher

[5] Pan American FPC Rate Schedule 236. Notwithstanding the foregoing provisions of this Article VII, the price to be paid by Buyer to Seller hereunder shall be at least equal to the highest price then being paid or contracted to be paid by Buyer or any other company while such other company is a subsidiary, parent, or affiliate of Buyer for gas from the East LaBarge Unit, adjusted for differences in quality and delivery conditions and all other pertinent factors.

prices are necessary to stimulate exploration and development, the evidence offered by the applicants as to the above contentions in justification of the price in these proceedings is the same as that adduced in the East LaBarge case through the same witnesses, and the applicants here are merely rearguing the same evidence. The conclusions thereon as set forth in the East LaBarge decision are also applicable to the evidence in these proceedings, and by this reference are incorporated herein.

As to the additional evidence in support of the claim of higher prices needed for an incentive to explore and develop natural gas, Humble refers to its refusal to accept a farm-out proposal from the Mountain Fuel Supply Company in the Green River Basin area, which was to be coupled with an agreement that if Humble found gas it would sell the same to Mountain Fuel at a price of 15 cents per Mcf. Humble's position is that the 15 cents per Mcf price was insufficient to justify it in committing funds to the proposal. It takes the position that it is not concerned with the cost of producing gas, but rather with the market price in this area as compared with other areas in the face of its position that El Paso need not maintain a uniform price to all producers along its system. It is argued that the Mountain Fuel contracts resulting from farm-out agreements cannot be used as a basis for comparison because "they are not predicated on the competitive nature of the industry and do not result from arm's length negotiations." The farm-out arrangements are accepted practice in the industry and, as disclosed in these proceedings, are entered into by these applicants. Further, the record herein does not disclose that such arrangements are entered into with Mountain Fuel on other than the free choice of the contracting parties. The fact that a party refuses to pay as much for gas as Humble demands is evidence of arm's length bargaining.

It is argued that Pan American decided that it was not economically attractive to continue developing the properties for deep Frontier gas if it was not permitted to receive its contracts price for the gas. Thus, it negotiated the trade with Belco whereby Pan American acquired interest in the oil producing properties for its deep gas producing rights in the area subject to these proceedings. The short answer to this argument is that Belco was willing and did make the trade for the gas rights held by Pan American.

The main thrust of applicants' claim for the contract price as being necessary to stimulate exploration and development of gas by them in this area rests upon the testimony given and an exhibit of trends introduced through a consulting economist. It is contended through this witness that the contract price here in question may be tested as to its reasonableness by reference to the industry's financial requirements. To establish these requirements, reliance is placed upon certain supply, demand, cost, revenue, and market price trends. These trends are derived from selected data from the Census of Mineral Industries, United States Bureau of Mines, Mineral Year Book, and trade publications, grouped principally in the following four categories: (1) the entire United States; (2) the States of Colorado, Montana, Utah, and Wyoming; (3) the States of Kansas, New Mexico, Oklahoma, and Texas; and (4) a combination of the foregoing eight States.

From these trends, the witness contends that there is a need for gas prices to rise steadily until the various trends, such as decline in productivity per foot drilled, increase in cost of production, and decline in ratio of new supply to net production have been reversed. These trends will be reversed, he observes, when prices rise high enough to bring forth the supplies needed to equal demand. Thus, it is claimed that the contract price here fixed by the bargaining process is reasonable as a decline is shown, according to these trends, occurring in new supplies in relation to the demand. The witness takes the position

that the only meaningful and relevant costs are the total industry costs and it is not possible to relate these producers' financial requirements to either area prices or specific supply prices except through the mechanics of the competitive market system, which basically is supply and demand, and at the same time maintains that the incentive is merely in terms of managerial estimates of whether or not they can break even and make a profit from particular commitments of capital. The latter is also in line with the producers' argument that the proposed price in these certificate proceedings should be left standing and found to be in line if it is within the pattern of prices which do not yield an excessive profit level, or which have not risen more rapidly than cost, and that the profit must be commensurate with the financial hazards involved. The difficulty in these proceedings is that the record does not disclose the cost necessary to make such determinations or what profits the applicants will or expect to receive from the sale of the gas to El Paso.

The foreging trends admittedly do not include significant categories of cost, and include costs associated with the production of total hydrocarbons. Also, the market price trends include prices which are subject to both Commission and court review, contrary to the holding in *United Gas Improvement Company* v. *Federal Power Commission*, 283 F. 2d 817 (CA9), and *Public Service Commission of New York* v. *Federal Power Commission*, 287 F. 2d 146 (CADC). This witness was unaware that producers engaged in supplying different types of material from their leases do estimate the cost of each product for the purpose of measuring the relative profitability of various operations and as a general yardstick for resting the adequacy of sales prices.*

The allocation of joint costs is a common accounting practice, as pointed out by the Commission in *Northwestern Electric Company*, 2 FPC 327, 335–6:

> * * * Under the systems of accounts generally in effect in the past for electric utilities, and also under the present system, utility officials have been and are permitted considerable discretion in accounting for certain joint and other costs which cannot clearly be classified as plant costs or operating expenses. This is particularly true as to those items which are subject to proration or allocation. * * *

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*E. E. Hunter, of Humble Oil & Refining Co., Houston, Texas, in a Feature Article, Journal of Petroleum Technology, July 1954, pointed out that oil producing companies should change their method of accounting for gas under present day conditions, stating in part:

Petroleum producers have been engaged for many years in supplying several different types of materials from the leases they operate. Some leases produce crude oil and casinghead gas, others produce gas-well gas and condensate, and still others produce all four of these materials. Therefore, the problem of allocating costs between these intermingled products is not a new one.

* * * * *

This problem of allocating common costs is not peculiar to the petroleum producing industry. For example, the meat packing, milling, chemical, lumber, and petroleum refining industries are all faced with the problem of allocating common costs between two or more joint products. The difficulty or impossibility, of allocating such costs 'exactly' by no means lessens the need for some careful estimates of the cost of each product for the purpose of measuring the relative profitability of various operations and as a general yardstick for testing the adequacy of sales prices. Each industry has developed cost accounting procedures that are logical under the prevailing operating circumstances. As conditions change, the accounting procedures change with them. There is no reason why petroleum producers cannot change their traditional custom of considering that all costs are applicable to crude oil, just as other industries have changed their customs when necessary.

The discussion that follows will be devoted principally to the method of allocating producing cost that has been adopted by Humble Oil & Refining Co.***

> The company claims that the cost of public utility plant is a fact not at all dependent upon any accounting practices. We know that the cost of any utility plant is the resultant of the allowable accounting discretion of the utility as exercised within the limit permitted by the system of accounts, but the utility having exercised such allowable discretion is thereafter bound by the cost resulting therefrom. Many expenditures made by a utility must be assigned, allocated, or prorated on the basis of judgment, to the various plant and operating accounts. The cost of plant is dependent upon those assignments, allocations, and prorations, just as operating expenses are dependent thereon.

While the Commission has pointed out that the justification of prices in certificate proceedings need not entail the showing required in rate cases, this does not mean that such justification can be made on evidence unacceptable in rate cases. As late as June 1, 1961, the Commission, in *Alfred C. Glassell, Jr., et al.*, Docket No. G-9278, a producer rate proceeding under Section 5 of the Natural Gas Act, stated:

> In determining the rate base of natural gas companies in the administration of the Natural Gas Act, we have consistently refused to give weight to evidence of reproduction cost, price trends or current market value. These determinations have so frequently been made and upheld by the courts that we believe it unnecessary to review again the underlying considerations for this administrative judgment. [25 FPC 1071 at 1073]

In *United Gas Improvement Co.* v. *F.P.C.*, 290 F. 2d 147, 148 (CA5), the Court, in passing upon the granting of a certificate of public convenience and necessity under Section 7 of the Natural Gas Act, stated:

> As we have pointed out in the companion case No. 18,112, the record makes it clear that the finding of public convenience and necessity here is based too strongly on the fact that arm's length dealing and the effect of supply and demand required Transco to agree to the disputed price, rather than that the price had any relation to what might ultimately be found to be a just and reasonable price.

The evidence does not support the proposed price of 18½ cents per Mcf as necessary to the present or future public convenience and ncessity, and, if allowed, the unsupported price will be another inflationary step adversely influencing the cost of gas delivered off the El Paso system. As heretofore pointed out, the present going firm price for gas produced in this area is 15 cents per Mcf at a pressure base of 14.65 psia, and the certificates to be issued should be conditioned to reflect this price.

The argument advanced by the State of California that the indefinite escalation clauses set forth in the contracts which were executed prior to April 3, 1961, should be held inoperative has already been considered by the Commission at the time it adopted Order No. 232A, on March 31, 1961, and no justification for the attaching of such a condition has been shown in this record. Southern California contends that the one cent per Mcf five-year periodical escalations in price should be related to the conditioned price of 15 cents rather than to the 18½ cent contract price. The determination of the rate level for sales of gas to be made in the future can be more properly made under the circumstances existing at the time of the filing for the increase, and should not be passed upon at this time.

ADDITIONAL FINDINGS AND CONCLUSIONS

Upon consideration of the record in these proceedings, it is found and concluded, in addition to the findings and conclusions heretofore stated, that:

(1) El Paso is a natural-gas company within the meaning of the Natural Gas Act, and its facilities for which a certificate is requested will constitute an integral part of El Paso's transmission system and will be used to transport natural gas moving in interstate commerce for resale to ultimate consumers. The construction and operation of such facilities are subject to requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(2) El Paso is a qualified applicant and is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(3) The above-referred to facilities and the operation thereof, including the sale of natural gas, are required by the public convenience and necessity and a certificate authorizing the same should be issued on the terms and conditions of this order, which terms and conditions are reasonable and required by the public convenience and necessity.

(4) Humble, Belco, and Beneficial are now, or will become upon the commencement of the sale of natural gas as proposed in these proceedings, natural-gas companies within the meaning of the Natural Gas Act as independent producers of natural gas as defined in the Commission's regulations, and the sales of natural gas for which certificates are requested will be made in interstate commerce for resale for ultimate public consumption, and such sales, together with the construction and operation of facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) Humble, Belco, and Beneficial are qualified applicants and, subject to the requirements of this order and the conditions of the certificates issued to them, are able and willing properly to do the acts and to perform the service proposed, and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(6) The sale as proposed of natural gas by Humble, Belco and Beneficial to El Paso, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity, if made at a rate not in excess of 15 cents per Mcf at a pressure of 14.65 psia, and certificates authorizing the same should issue to each of them upon the terms and conditions of this order, which terms and conditions are reasonable and required by the public convenience and necessity.

(7) The application of Pan American should be dismissed, and the temporary certificate issued pursuant thereto should be rescinded.

(8) The additional conditions to the certificates, as requested, are not required by the public convenience and necessity and should be denied.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission, that:

(A) A certificate of public convenience and necessity hereby is issued to El Paso for the construction and operation of the facilities referred to above, all as more fully described in its application in these proceedings, for the transportation and sale of natural gas in interstate commerce subject to and upon the terms and conditions of this order.

(B) Certificates of public convenience and necessity hereby are issued to Humble, Belco, and Beneficial for the sale as proposed of natural gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, upon the terms and conditions of this order.

(C) As conditions to the authorization herein granted, Humble, Belco, and Beneficial, the initial price for the sale of gas as proposed to El Paso shall be 15 cents per Mcf at a pressure of 14.65 psia in substitution for the initial price provided for in the contracts and the producers shall file supplements to their filed rate schedules reflecting the 15 cent price.

(D) The certificates herein issued shall be accepted in writing, under oath, within 30 days from the date of issuance of this order.

(E) The certificates issued herein are not transferable and shall be effective only so long as each of the applicants continues the acts and operations herein authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations, and orders of the Commission.

(F) The grant of the certificates herein shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or Part 154 of the Commission's regulations thereunder, requiring the filing of rate schedules for the service herein authorized, and is without prejudice to any findings or orders which have been or hereafter may be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicants.

(G) The application for a certificate of public convenience and necessity by Pan American hereby is denied, and the temporary authorization issued thereunder is rescinded.

(H) The conditions to the certificates here issued, as requested by the State of California and Southern California pertaining to the price provisions for the sale of gas, other than as imposed herein, are denied.

ALVIN A. KURTZ,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

VILLAGE OF LOUISVILLE, ILLINOIS, DOCKET NO. CP61-346

ORDER TERMINATING PROCEEDING

(Issued June 11, 1962)

On June 30, 1961, the Village of Louisville, Illinois (Applicant), Clay County, Illinois filed an application for an order pursuant to Section 7(a) of the Natural Gas Act directing Trunkline Gas Company to establish physical connection of its transmission facilities with the facilities proposed to be contructed by Applicant and to sell and deliver to Applicant up to 506 Mcf per day. Notice of this application was issued on November 6, 1961 (26 FR 10709).

Applicant has previously intervened in the consolidated proceeding, *American Louisiana Pipe Line Co., et al.*, Docket No. 2306, *et al.*, seeking a similar order against Trunkline. By our order issued May 17, 1962, 27 FPC 967, affirming the decision of the presiding examiner, Trunkline was ordered to establish physical connection of its transportation facilities with Applicant's proposed facilities and to sell up to the required quantity of natural gas. The instant proceeding has thereby been rendered moot. No further purpose would be served by the continuance of this proceeding and the proceeding herein should be terminated.

The Commission orders:

The proceeding in Docket No. CP61–346 is hereby terminated.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., and Harold C. Woodward.

REVISION OF ANNUAL REPORT FORM PRESCRIBED FOR CLASS C AND CLASS D PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE FEDERAL POWER ACT, F.P.C. FORM NO. 1–F, DOCKET NO. R–213

ORDER NO. 250

ORDER PROMULGATING A REVISED ANNUAL REPORT FORM FOR CLASS C AND CLASS D PUBLIC UTILITIES AND LICENSEES

(Issued June 11, 1962)*

The Commission has under consideration in this proceeding the revision of its F.P.C. Form No. 1–F, Annual Report Form Prescribed for Class C and Class D Public Utilities and Licensees Subject to the Provisions of the Federal Power Act and § 141.2, Part 141, Subchapter D—Approved Forms, Federal Power Act, Chapter I, Title 18, Code of Federal Regulations (CFR), prescribing F.P.C. Form No. 1–F. That form, as revised, is prescribed hereinafter effective for use in reporting for the calendar year beginning January 1, 1961 or subsequently during the calendar year 1961 if an established fiscal year is other than the calendar year, and years thereafter.

The various schedules comprising F.P.C. Form No. 1–F now prescribed in § 141.2 (18 CFR 141.2) correspond to, and appear as pages 1–6 of the Commission's F.P.C. Form No. 1–F, Public Utilities and Licensees, Class C and Class D.[1]

This proceeding was commenced by notice of proposed rule making served upon interested parties, including State and Federal regulator agencies, and by publication in the Federal Register on April 4, 1962 (27 F.R. 3206). As proposed, the subject matters and revisions in § 141.2, and the General Instructions and other Schedules comprising F.P.C. Form 1–F were set forth in the notice of proposed rule making and attached forms of proposed revised Schedules served upon the aforesaid interested parties and filed as a part of the notice submitted to the Federal Register for publication. The notice of proposed rule making invited the submission to the Commission of written data, views, comments and suggestions concerning the proposed revisions of F.P.C. Form

* Published in the Federal Register on June 15, 1962, (27 F.R. 5706).

[1] For reporting years 1939 through 1958 this Commission had separate annual report forms for Class C and Class D electric utilities and licensees. The report form for Class C companies was prescribed by Order No. 55 of September 7, 1938 (3 F.R. 2254, September 20, 1938) and amended by Order No. 76 of September 24, 1940 (5 F.R. 3860, October 1, 1940), Order No. 110 of December 21, 1943 (8 F.R. 17337, December 28, 1943), and Order No. 150 of November 22, 1949 (14 F.R. 7248, December 2, 1949). The report form for Class D companies was prescribed by Order No. 56 of September 7, 1938 (3 F.R. 2255, September 20, 1938), and amended by Order No. 77 of September 24, 1940 (5 F.R. 3860, October 1, 1940), Order No. 111 of December 21, 1943 (8 F.R. 17337, December 28, 1943), and by Order No. 150 of November 22, 1949 (14 F.R. 7248, December 2, 1949).

The combined report form, for Class C and Class D companies, F.P.C. Form No. 1–F was promulgated by Order No. 212 of March 26, 1959 (24 F.R. 2526, April 1, 1959) (21 FPC 387).

No. 1–F and Part 141 on or before April 20, 1962. No filing responsive to the notice of proposed rule making has been received.

The exact nature of each of the revisions in Form 1–F is fully set forth in the respective accompanying schedule pages. The changes would be accomplished mainly through modification of existing schedules. One new schedule, Transmission Lines Added During the Year, has been added. The revised Annual Report Forms has been adapted to changes prescribed in the Uniform System of Accounts, Prescribed for Public Utilities and Licensees effective January 1, 1961.

The Commission finds:

(1) The notice and opportunity to comment in this rule making proceeding with respect to the matters presently before the Commission in the manner as described above are consistent and in accordance with the procedural requirements of Section 4 of the Administrative Procedure Act.

(2) In view of the foregoing, and upon consideration of all relevant matters presented it is necessary and appropriate for the purposes of the Federal Power Act that:

(a) The revised Annual Report Form as set forth in annexed Appendix A be adopted and promulgated as this Commission's F.P.C. Form No. 1–F effective for use in reporting for the calendar year beginning January 1, 1961 or subsequently during the calendar year if an established fiscal year is other than the calendar year, and years thereafter; all as hereinafter provided.

(b) Section 141.2, Part 141, Subchapter D—Approved Forms Federal Power Act, Chapter I, Title 18, Code of Federal Regulations be amended to read as hereinafter provided.

(3) Good cause exists for adoption and promulgation of the matters referred to above immediately upon issuance of this order; all as hereinafter provided.

The Commission acting pursuant to the Federal Power Act, as amended particularly Sections 3(13), 4 (a), (b), (c), 301 (a), 302, 304, 309 and 311 thereof (16 U.S.C. 796 (13), 797 (a), (b), (c), 825 (a), 825a, 825c, 825h, and 826j *orders:*

(A) The revised Report Form as set forth in annexed Appendix A is adopted and promulgated as this Commission's F.P.C. Form No. 1–F effective for use in reporting for the calendar year beginning January 1, 1961, or subsequently during the calendar year 1961 if an established fiscal year is other than the calendar year, and years thereafter.

(B) Section 141.2, Part 141, Subchapter D—Approved Forms, Federal Power Act, of Chapter I of Title 18 of the Code of Federal Regulations, is amended to read as follows:

§ 141.2 *Form No. 1–F; Annual Report for public utilities and licensees, (Class C and Class D)*

(a) The form of Annual Report for public utilities and licensees, Class C and Class D, designated as F.P.C. Form 1–F in the Commission's Regulations under the Federal Power Act is prescribed for the year 1961 and thereafter.

This report form is not prescribed for municipalities as defined in Section 3 of the Federal Power Act; i.e., a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, or distributing power.

(b) Each public utility or licensee, as defined in the Federal Power Act which is included in Class C or Class D as defined in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees, effective January 1,

1961, shall prepare and file with the Commission for the year beginning January 1, 1961 or subsequently during the calendar year 1961 if its established fiscal year is other than the calendar year, and for each year thereafter, on or before the last day of the third month following the close of the calendar year or other established fiscal year (except that such reports for the calendar year 1961 or a fiscal year beginning during 1961 may be filed on or before July 16, 1962 or one month after the end of the fiscal year whichever is later) an original and one conformed copy of the above-designated F.P.C. Form 1–F, all properly filled out and verified. One copy of said report should be retained by the correspondent in its files. The conformed copy may be a carbon copy if legible.

(c) This annual report contains the following schedules:

Identification
General Instructions
General Information
Security Holders and Voting Powers
Officers and Directors
Comparative Balance Sheet
Accumulated Provision for Depreciation and Amortization of Utility Plant
Capital Stock
Long-Term Debt
Condensed Income Statement
Earned Surplus
Electric Sales Data for the Year
Sales of Electricity for Resale
Electric Operation and Maintenance Expenses
Purchased Power
Utility Plant
Generating Station Statistics
Transmission Line Statistics
Transmission Lines Added During Year
Verification

[Authority: Sections 3(13), 4 (a), (b), (c), 41 Stat. 1065, as amended, Sections 301 (a), 302, 304, 309, 311, 49 Stat. 838, 839, 854, 855, 858, 859; 16 U.S.C. 796 (13), 797 (a), (b), (c), 825 (a), 825a, 825c, 825h, 825j.]

(C) This order shall be effective upon the date of issuance thereof.

(D) The Secretary of the Commission shall cause prompt publication of this order to be made in the Federal Register.

STANDARD OIL COMPANY OF CALIFORNIA, DOCKET NO. CI60–333; DORSEY BUTTRAM, CI60–442; GEORGE P. CAULKINS, JR., CI60–560; GULF OIL CORPORATION, CI60–636

OPINION AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 11, 1962)*

Syllabus

1. Existing Utah sales cannot be relied upon in determining price level for Red Wash sales here; Uintah Basin sales do not represent sufficient quantities or enough contracts to constitute established and stable market; other

* Designated Commission opinion No. 359. Initial decision appears on page 1162. Modified and affirmed; rehearing denied by order issued August 6, 1962, 28 FPC 292. Affirmed, 315 F. 2d 652 (CA 10–1963).

sales, while in sizable quantities, are in a wholly unrelated geological producing and marketing area. P. 1157.

2. Price line for sales in neighboring Wyoming may appropriately be applied to Red Wash sales since this producing region with respect to geology, geography, producing and marketing, is quite similar to Uintah Basin. P. 1157.
3. *Distinguishing Panhandle* case, Commission *rejects* producer contention that in line price should apply to gas at the wellhead. P. 1158; 1159.
4. Referring to *Opinion 358* Commission *concludes* 15.384 cent price there authorized should apply to Red Wash sales. P. 1158; 1160.
5. Additional allowance for gathering, compressing, etc. is not applicable in other areas where gas is traditionally sold at tailgate of plant; in line price in each area is determined at customary delivery point in that area. P. 1159.
6. Producers' take-or-pay provisions allowed, subject to ultimate disposition in Docket No. R–199. P. 1160.
7. Commission *issues* certificates of public convenience and necessity under Section 7 of the Natural Gas Act. P. 1161.

Justin R. Wolf, Eugene Threadgill, and V. P. Cline for Standard Oil Company of California.

Barth P. Walker for Dorsey Buttram.

Keith L. Brown for George P. Caulkins, Jr.

Anthony C. Riddlesperger and *John E. Thomas* for Gulf Oil Corporation.

J. David Mann, Jr., William E. Holtzinger, Jr. William E. Zeiter, Harry P. Letton, Jr., Henry F. Lippitt, II., Milford Springer, and *Robert M. Olson, Jr.* for Southern California Gas Company.

William M. Bennett, William L. Cole, and *J. Calvin Simpson* for the People of the State of California, and Public Utilities Commission of the State of California.

F. T. Searls and *Malcolm H. Furbush* for Pacific Gas & Electric Company.

Allen R. Grambling and *George D. Horning, Jr.* for El Paso Natural Gas Company.

John Paul Geneau for Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

Ross, *Commissioner:*

This proceeding arises under Section 7 of the Natural Gas Act (Act). The applicants are independent producers of natural gas. They seek certificates of public convenience and necessity for the sale of natural gas from the Red Wash field, Uintah County, Utah, to El Paso Natural Gas Company (El Paso).

The Red Wash field is a unitized operation in which all of the producer applicants have participating interests. Standard Oil Company of California (Standard) is the operator of the unit and majority interest holder, having a 97.64 percent interest.[1] The interest holdings of the other applicants are as follows: Gulf Oil Corporation 1.18 percent, Dorsey Buttram 0.885 percent, and George P. Caulkins, Jr. 0.295 percent.

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[1] Effective January 1, 1961, Standard's interest in the properties here involved were transferred to the California Oil Company, Western Division, a wholly owned subsidiary. Appropriate filings have been made with the Commission to effect this succession of interest. Accordingly, all references to Standard herein, and the certificate herein issued to Standard, shall extend to the California Oil Company, Western Division, as successor in interest to Standard.

The Red Wash field contains both casinghead gas and dry gas. Since the discovery oil well was drilled in 1951, the field has been developed to include 123 producing oil wells and 6 gas wells. The gas wells have not as yet been produced, and until 1960, when the applicants received temporary authorization to sell the Red Wash gas to El Paso the field was operated solely for the production of oil and the recovery of liquids from the casinghead wells, the residue gas being compressed and reinjected to aid in the production of oil.

The applicants propose to sell and, in accordance with the temporary authorization granted, are now selling gas to El Paso at the tailgate of their Red Wash extraction plant. The gas is gathered, processed for the removal of liquid hydrocarbons, compressed and dehydrated by the applicants, and is delivered into El Paso's lateral at 900 pounds pressure with a Btu content of 1,055 Btu's per cubic foot.[2] As required by the Commission's temporary authorization, the gas is presently being sold at a conditioned price of 15 cents per Mcf at 15.025 psia.

The main issue in this proceeding is the initial price to be charged for the Red Wash gas. Under their contracts with El Paso, the applicants have agreed to sell and deliver to the pipeline a minimum of 82,125,000 Mcf of gas[3] over a 20-year period, at an initial price of 18.5 cents per Mcf. The contracts provide for periodic increases of 1.0 cents per Mcf every five years, or such greater amounts as the parties may negotiate on the basis of a fair market price.[4] The contracts further provide for reimbursement to the applicants of 75 percent of all future taxes. The applicants are required to deliver, and El Paso is required to take-or-pay for an average of 11,250 Mcf per day on an annual basis, or approximately 4,100,000 Mcf per year. On a daily basis, El Paso is required to take and pay for a minimum of 7,500 Mcf, and may take up to 15,000 Mcf per day. The applicants, however, are not required to deliver more than an average of 11,250 Mcf per day on an annual basis.[5] If, in any year, El Paso is required to pay for gas which it does not take, the contracts provide that El Paso may take the gas so paid for over a period of five years, or over the remaining term of the contract, if less than five years. If El Paso has not taken all of the gas for which it has paid by the time the contracts expire, it may take such gas during the following year up to the maximum daily delivery obligation of the applicants immediately prior to the termination of the contracts. The contracts provide no upward adjustment in price based on the Btu content of the gas. The contracts, however, do require a minimum heating value of 985 Btu's per cubic foot, and provide that if El Paso wishes to take delivery of gas containing less than 985 Btu's per cubic foot, it may do so at

[2] By order issued February 2, 1960, in Docket No. G-20051, El Paso was authorized to construct and operate 8.9 miles of lateral connecting its main transmissin line with the Red Wash plant. The cost of this was $412,412. (23 FPC 287).

[3] Recoverable reserves in the Red Wash field are estimated at 182,000,000 Mcf. The applicants, upon notice, may increase the contract quantities to El Paso.

[4] Under Section 154.93 of the Commission's Regulations under the Natural Gas Act, as amended effective April 13, 1961, and April 2, 1962, this renegotiation provision would be inoperative and of no effect as part of applicants' rate schedules if their contracts were executed on or after April 3, 1961, and the contracts themselves would be rejected as rate schedules if the contracts with this provision were executed on or after April 2, 1962. Inasmuch as the contracts in this case were executed prior to April 3, 1961, the renegotiation provision is here allowed, although contrary to present Commission policy; and its allowance is not to be construed as a waiver or exception to that policy.

[5] If, as referred to in footnote 3 above, the applicants make additional quantities of gas available to El Paso, El Paso is required to take and pay for 50 percent of the daily availability on a daily basis, and to take-or-pay for 75 percent of the daily availability on an annual basis. The applicants are not required to deliver more than 75 percent of the daily availability on an annual basis.

a price reduced proportionally to the reduction in heating value below the minimum required.

On September 28, 1961, the examiner who presided at the hearing in this proceeding, issued an initial decision recommending that certificates of public convenience and necessity be issued to the applicants as proposed, subject, however, to the condition that the initial price shall be 15 cents per Mcf at 15.025 psia in substitution for the 18.5-cent initial contract price proposed, and that the applicants' filed rate schedules be supplemented to reflect the 15-cent price. Exceptions to the examiner's decision were subsequently filed by each of the applicants, by the People of the State of California and the Public Utilities Commission of the State of California (interveners in this proceeding, and jointly referred to as California),[6] and by staff.

At the time the examiner issued his decision, the Commission had not established any ceiling price level for initial service in the State of Utah. The Commission's *Statement of General Policy No. 61–1*, issued September 28, 1960, 24 FPC 818, under which the Commission inaugurated a policy of area pricing, prescribed a ceiling level for initial service rates of 15 cents per Mcf at 15.025 psia in neighboring Colorado, and 15 cents per Mcf at 14.65 psia (15.384 cents at 15.025 psia) in neighboring Wyoming, but was silent with respect to Utah. In the absence of a policy determination by the Commission as to the in-line price to be used as a guide in certificating sales in Utah, the examiner, upon an analysis of certificated sales in Utah, Colorado, and Wyoming, concluded that the appropriate pricing area for determining a proper initial price for gas sold from the Red Wash field, which is located in the northeastern corner of Utah, is northeastern Utah, northwestern Colorado, and southwestern Wyoming. In the pricing area thus determined, the examiner concluded that the in-line price governing the Red Wash sale is 15 cents at 15.025 psia, the price prescribed by the temporary certificates issued to the applicants.

The applicants take exception to the examiner's determination of the proper pricing area, which excludes the Paradox Basin in southeastern Utah where the Commission has certificated sales to El Paso from the Aneth field at 17.7 cents per Mcf. The applicants further except to the examiner's 15-cent price condition as ignoring the need for incentive to carry on exploration and development in the Uintah Basin, and as failing to make any allowance for the fact that the Red Wash gas is gathered, dehydrated and compressed by the applicants before delivery to El Paso. They also contend that the 15-cent price condition is erroneously based on a 15.025 pressure base, and that if a 15-cent price condition is to be imposed, it should be 15 cents at 14.65 psia, which is the equivalent of 15.384 cents at 15.025 psia. California takes exception to the examiner's failure to require the applicants to produce cost evidence in support of their proposed initial price, and in the absence of such cost evidence urges that the certificates be denied, or the proceeding reopened for the taking of such evidence. California also excepts to the issuance of certificates to the applicants on the ground that they have failed to show El Paso's need for the Red Wash gas.[7] Staff's exceptions contend that the examiner erred in considering sales outside

[6] Other interveners in this proceeding are: Southern California Gas Company and Southern Counties Gas Company of California (jointly referred to as the Southern California Companies), Pacific Gas and Electric Company (P.G.&E.), and El Paso.

[7] California did not raise the question of need at the hearing, but first raised it in its brief after the hearing had concluded. The examiner found that El Paso's need for gas is a well established fact publicly declared by the Commission in recent proceedings (citing cases); and that if California had any evidence or basis for contending otherwise, the matter properly should have been advanced at the hearing, where the other parties would have an opportunity to present evidence confirming El Paso's need for the gas.

of the State of Utah in determining the proper initial price to be allowed the applicants in this proceeding, and that a comparison of the proposed sales with other sales in Utah justifies an initial price of no more than 12 cents per Mcf. Staff also questions the propriety of the examiner's consideration of the question of El Paso's need for gas, since that question is not properly an issue in this proceeding, having already been disposed of in the certificate proceeding in Docket No. G–20051, wherein El Paso was authorized to construct and operate the facilities required to take delivery of the Red Wash gas.

The Red Wash field is located in an area of northeastern Utah known geologically as the Uintah Basin. This area, and the Paradox Basin in the southeastern corner of the state, are the only areas in Utah from which natural gas is presently being produced and sold in interstate commerce. The first sale of gas in Utah certificated by the Commission was from the Bar–X field in the Uintah Basin in 1957. Since then the Commission has certificated sales from the Westwater field, also in the Uintah Basin, and from the Aneth field in the Paradox Basin. The gas in each case is sold to El Paso—the Aneth gas for delivery to markets in southern California, and the Bar–X and Westwater gas for delivery to markets in the Pacific Northwest. Like the other gas from the Uintah Basin, the Red Wash gas is being taken into El Paso's Pacific transmission line near the Utah-Colorado border for delivery to the Pacific Northwest.

The record shows that the Bar–X sales are wellhead sales at 12 cents per Mcf for gas delivered at 500 psig and containing 1000 Btu's per cubic foot. Staff estimates these sales to cover 2,331,000 Mcf annually. The Westwater sales are also based on a wellhead price of 12 cents, and involve gas delivered at 900 psig with a Btu content of 900–985; but the Westwater gas is gathered and transported to El Paso's main line through a lateral constructed by the producers, for which service El Paso pays an additional charge of 5.5 cents per Mcf. The Westwater sales are estimated at 3,240,000 Mcf annually, but are expected to decline to less than one million within three to six years. In the Aneth field in the Paradox Basin, El Paso is purchasing an estimated 34,000,000 Mcf annually at 17.7 cents per Mcf, delivered at 850 psig with a Btu content of 950 at a central point in the field.

In our opinion, these existing Utah sales cannot be relied upon in determining a price line for the Red Wash sales here proposed. The Bar–X and Westwater sales do not represent sufficient quantities of gas, or enough contracts, to constitute an established and stable market for gas in the Uintah Basin. The Aneth sales, although of sizeable quantities, are in a geological producing area and a marketing area wholly unrelated to the Red Wash sales, and cannot be found to be part of the same pricing area as the Uintah Basin. It is necessary, therefore, to look beyond the boundaries of Utah to sales in the adjoining states of Colorado and Wyoming to find comparable sales which may be used as a basis for determining the price line applicable to the Red Wash sales.

As noted above, the Commission has established a ceiling price for Wyoming of 15 cents per Mcf at 14.65 psia, which is the equivalent of 15.384 cents at a 15.025 pressure base. The Colorado ceiling is 15 cents per Mcf at 15.025 psia. The record shows substantial sales of gas in Sublette, Lincoln, and Sweetwater Counties in southwestern Wyoming at the ceiling level of 15.384 cents. This 15.384-cent gas is gas well gas of pipeline quality, delivered at pressures up to 860 psig at the wellhead. It is produced in a region which, with respect to geology, geography, and the conditions of exploration, production and marketing, is quite similar to the Uintah Basin of northeastern Utah. We have found that in the absence of compelling evidence to justify some higher price, the public convenience and necessity requires the sale of this Wyoming gas at a price no

higher than 15.384 cents.[8] In our opinion, this price line for sales in the neighboring Wyoming area may appropriately be applied to the proposed Red Wash sales in the Uintah Basin. A review of sales in the adjoining Colorado counties, as found by the examiner, does not require any different conclusion.

Statement of General Policy No. 61–1 makes it clear that the price levels established by the Commission as area ceilings apply to pipeline quality gas as that term is generally understood in each area. There is no evidence in the present proceeding to show that the Red Wash gas as delivered to El Paso is not of a quality consistent with what is generally understood in this area to be pipeline quality gas. On this basis it would appear that the 15.384-cent price properly should be applied to the Red Wash gas as delivered to El Paso at the tailgate of the Red Wash plant.

The producers contend, however, that the in-line price applies to gas at the wellhead, and that they should be granted an allowance over and above the wellhead price line for gathering, dehydration, and compresion . It is true that in a recent case we allowed producers in another area to collect an additional allowance for such services beyond the wellhead.[9] There are basic factual differences, however, between that case, which we shall refer to as the *Panhandle* case, and this one, which clearly distinguish the two and require different results.

In the *Panhandle* case, the gas in question was gas well gas produced from a gas-condensate field; and although this gas was gathered, dehydrated, and compressed by the producers, it appeared from the record that sales of gas well gas in that area of Oklahoma normally were made at the wellhead or at the outlet of a wellhead separator without being gathered, dehydrated, or compressed by the seller.[10] Inasmuch as Panhandle would have had to render these services for itself had it purchased the gas at the wellhead, and since the gas at the wellhead was of pipeline quality as understood in that area, we found that the producers should be allowed to recover a properly allocable portion of the cost of gathering, dehydration, and compression in addition to the area ceiling price applicable to the gas at the wellhead. We further found this result to be in the public interest, since such cost associated with the sale of gas in that area would normally be borne by the pipeline purchaser and passed on to the ultimate consumer.

In the present proceeding we are dealing with a wholly different situation. The gas in this case is being produced in an area located far from the Oklahoma area under consideration in the *Panhandle* case—an area in which there do not appear to be the same clear cut and well established practices found in Oklahoma. The gas which the producers are now selling to El Paso is casinghead gas produced from an oil field. Such gas, produced in conjunction with oil, is not of merchantible quality until it is processed for the removal of liquids in an extraction or gasoline plant. Of necessity this gas must be gathered in order to be processed, and both the gathering and the processing are an essential step in the production of pipeline quality gas. It is clear, therefore, that the in-line price for gas of pipeline quality in the Red Wash field includes that allocable cost of gathering and processing the casinghead gas.

With respect to the dehydration and compression of this gas, it appears that these operations are an integral part of the processing operation which the

[8] See Opinion No. 358, *El Paso Natural Gas Co., et al.*, Docket No. CP60–72, *et al.*, issued today, *Supra*, p. 1134.

[9] *Panhandle Eastern Pipe Line Co., et al.*, Docket No. CP60–103, *et al.*, Opinion No. 350, issued January 15, 1962, 27 FPC 35.

[10] In referring to dehydration, we are speaking of dehydration through an absorption process, and not of mechanical separation of water in wellhead separators.

producers have carried on at the Red Wash plant for the past ten years, whereby dehydrated residue gas has been produced in the plant, and has been, and in part is still being, reinjected under pressure to aid in the recovery of oil. Since there is nothing to indicate that the producers are rendering any service in connection with the sale of the casinghead gas to El Paso beyond what they have found to be a necessary part of their processing operation, we are of the opinion that the in-line price includes both the dehydration and compression of the casinghead gas, and is applicable to this gas as delivered to El Paso at the tailgate of the Red Wash plant in accordance with the terms and conditions of the producers' contracts.

Thus far our discussion of the producers' request for an allowance over the in-line price for gathering, dehydration, and compression has been confined to a consideration of the casinghead gas which the producers are now selling to El Paso. Apparently, the producers intend to rely on the casinghead gas to the extent that it is available to meet El Paso's contract requirements, and do not plan to begin production of their shut-in gas wells until some future time. However, the gas well gas when produced will be gathered by the producers and delivered to El Paso at the tailgate of the Red Wash plant together with the casinghead gas. To what extent the producers will utilize the existing casinghead gathering system for this purpose is not clear, and this would introduce a question of allocation; but to the extent that the producers will incur costs with respect to the gathering of the gas well gas, which are properly allocable thereto, the costs thereof should be treated as an allowance to the producers over and above the in-line price, which in this area is based on gas well gas at the wellhead. The producers, however, have not shown when they will begin production of the gas well gas; how much of such gas will be needed from time to time to meet their delivery obligations under the contracts; or what costs they expect to incur in gathering the gas to the Red Wash plant. Under the circumstances, we can make no allowance for the gathering of the gas well gas in this proceeding.[11]

The record is equally barren with respect to the expected water content and wellhead pressure of the gas well gas. There is no evidence to show that any dehydration or compression will be required for this gas to meet the quality standards of the contracts. In the absence of such evidence, there is certainly no basis for an allowance over the in-line price for dehydration and compression; and even if dehydration and compression were required to meet the conditions of the contracts, there would still be no basis for an additional allowance unless it were shown that the gas at the wellhead was of pipeline quality and that the additional services resulted in the saving of dehydration and compression costs which otherwise would have to be incurred by the pipeline, as in the *Panhandle* case.

As we noted above, there is nothing in the record before us which convinces us that the gas as delivered to El Paso in accordance with standards negotiated by the parties is not of pipeline quality as understood by them, or others, in this area. Furthermore, a review of the contracts which the Commission has approved in connection with sales in Wyoming, Colorado and Utah, reveals no consistent pattern with respect to dehydration and compression which would indicate that pipeline buyers in the area normally buy gas undehydrated and uncompressed at the wellhead. On the contrary, the record shows a number of contracts which require the producers to dehydrate their gas to meet the quality

[11] It should be noted that such allowance to producers is not applicable in other areas where gas is traditionally sold at the tailgate of a plant. The in-line price in each area is determined at the customary point of delivery in that area.

conditions for delivery under their contracts. At the same time, there is nothing in other contracts, not requiring dehydration, which would suggest that the gas delivered without dehydration is of any lesser quality with respect to entrained water than the gas which is delivered after dehydration. As for compression, we have already noted that the Wyoming ceiling, which is the in-line price governing the present sales, is actually based on sales at the wellhead of gas at 860 psig, a pressure sufficiently high to permit delivery into the buyer's pipeline without additional compression. There is no question but that the producers in Wyoming are not permitted an allowance over the ceiling price because their gas has a wellhead pressure which eliminates the need for the buyer to compress the gas at the point of delivery,[12] and there is no justification in terms of public convenience and necessity for allowing the producers in the Red Wash field in Utah any higher price for their gas delivered at comparable pessure. There is nothing in the concept of public convenience and necessity which would compel a finding on our part that consumers of gas purchased in the Red Wash field should be required to pay in excess of 15.384 cents per Mcf for the gas as delivered to El Paso.

El Paso's obligation to take gas or pay for it under its contracts with the producers is equal to the annual obligation of the producers to deliver gas. As found by the examiner, this constitutes a 100 percent take-or-pay requirement. The Southern California Companies who intervened in this proceeding argued for the adoption of a policy which would limit take-or-pay provisions to 80 percent, and sought to have the examiner condition the certificates in this proceeding accordingly. The examiner, however, allowed the 100 percent take-or-pay provisions without condition. He noted that the question of take-or-pay provisions is currently before the Commission in a rule-making proceeding in Docket No. R–199, and concluded that standardization of such provisions can only be accomplished properly when effected by general order of the Commission applicable to all producers similarly situated. The examiner is correct in this conclusion. However, as found by us in several recent cases where producers sought certificates for sales subject to 100 percent take-or-pay provisions,[13] the public interest requires that the certificates issued herein be conditioned so as to make our allowance of the proposed take-or-pay provisions subject to our ultimate disposition with respect to such provisions in Docket No. R–199.

With respect to El Paso's need for the Red Wash gas, and the exceptions of California and the staff relating thereto, we are of the opinion that staffs position is well taken, and that the question of need is not properly an issue in this proceeding, having already been disposed of in the certificate proceeding in Docket No. G–20051, wherein El Paso was authorized to construct and operate the facilities required to take delivery of the Red Wash gas.

The Commission finds:

(1) The applicants herein are independent producers of natural gas, and are, or upon initiation of the service herein proposed will be, "natural-gas companies" within the meaning of the Natural Gas Act, and are, or will be, engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission.

(2) The sales of natural gas proposed by the applicants, as referred to above and more fully described in their applications, are subject to the jurisdiction of the Commission; and such sales, together with the construction and operation

[12] See note 8 above.

[13] See the *Panhandle* case (Opinion No. 350), *supra*. *Michigan Wisconsin Pipe Line Co., et al.*, Docket Nos. CP61–102, *et al.*, Opinion No. 353, issued March 7, 1962, 27 FPC 449.

of any facilities subject to the jurisdiction of the Commission necessary therefor, are subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Subject to the requirements of our order herein and the conditions attached to the certificates herein issued, the applicants are able and willing properly to do the acts and to perform the service proposed, and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The sales proposed by the applicants, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, are required by the public convenience and necessity upon the conditions hereinafter set forth, and certificates should be issued to each of them as ordered below.

(5) The conditions attached to the certificates herein issued are required by the public convenience and necessity.

(6) Except as herein granted, the exceptions to the examiner's decision should be denied.

The Commission orders:

(A) Certificates of public convenience and necessity are hereby issued, upon the conditions hereinafter set forth, to each of the applicants in this proceeding for the sale of natural gas in interstate commerce for resale as proposed, and for the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, as more fully described above and in their applications.

(B) The certificates herein issued are granted upon the express condition that the initial price for the sale of gas shall not be in excess of 15 cents per Mcf at 14.65 psia (15.384 cents per Mcf at 15.025 psia), and that the applicants shall file supplements to their presently filed rate schedules reflecting the conditioned price as their initial price in lieu of the initial price provided in their contracts.

(C) The certificates herein issued are granted upon the further express condition that the allowance of the take-or-pay provisions in the applicants' contracts is subject to our ultimate disposition with respect to such provisions in the rule-making proceeding in Docket No. R–199. Upon the establishment, by regulation or policy statement, of a general policy governing such provisions in producer contracts, the applicants shall within 30 days thereafter file amended rate schedules in conformity therewith, acceptable to the Commission.

(D) The certificates herein issued are not transferable and shall be effective only so long as each of the applicants continues the acts and operations hereby authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations and orders of the Commission.

(E) The grant of the certificates herein shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act, or of Part 154 of the Regulations thereunder. Such grant is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicants. Further, the action in this proceeding shall not foreclose nor prejudice any further proceedings or objection relating to the operation of any price or related provision in the gas purchase contracts herein involved.

(F) The certificates herein issued are without prejudice to any action the Commission may determine to be necessary or appropriate as a result of the outcome of *United States* v. *El Paso Natural Gas Company and Pacific Northwest Pipeline Corporation*, Civil No. 143–57 (D. Utah).

(G) Except as herein granted, the exceptions to the examiner's decision are hereby denied.

DECISION

UPON APPLICATIONS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued September 28, 1961)

WESTON, *Presiding Examiner:* The main issue in this case is the proper initial price for gas sold by the above-captioned producers to El Paso Natural Gas Company. The gas comes from the so-called "Red Wash" field in northeastern Utah. It is being delivered currently under temporary authorization granted by the Commission to Standard Oil Company of California (Stancal) on April 15, 1960. The temporary authority reduced the initial contract price, 18.5 cents per Mcf at 15.025 psia, to 15.0 cents per Mcf at the same pressure, "without prejudice to such final disposition of the application for certificates as the record may require."

There is no indication in the record as to how the Commission arrived at the 15 cent level for this Utah gas. The Commission's *Statement of General Policy No. 61–1*, 24 FPC 818, does not prescribe any price level applicable to gas from that State. However, the 15 cent level is prescribed in the *Statement* for deliveries at 15.025 psia from the neighboring State of Colorado. For the neighboring State of Wyoming, 15 cents at 14.65 psia is prescribed, which translates to 15.384 cents at 15.025 psia.

Applicants contend that the permanent certificates of public convenience and necessity should be issued at the 18.5 cent level provided by the basic contracts. Staff contends for a 12 cent level; interveners contend as follows:

Southern California Gas Company and Southern Counties Gas Company of California (Southern California distributors)—15 cents per Mcf "or less;"

State of California and its Public Utilities Commission (California Commission)—12 cents per Mcf if a price line "must necessarily exist" absent cost of service evidence;

Pacific Gas and Electric Company (Pacific Gas)—between 12 cents and 15 cents per Mcf.

General Description of Project and Contract. Red Wash is a unitized field in which Stancal has a 97.640 percent participating interest and acts as the operator; Gulf's interest is 1.180 percent; and Buttram's and Caulkins' interests are, respectively, 0.885 percent and 0.295 percent. Red Wash is located on Federal and State lands; Utah and the United States receive the usual one-eighth royalties in respect of production. The field was discovered in 1951 by Stancal, which brought in a well producing 339 barels of 32 gravity oil per day, plus about 809 Mcf per day of wet gas. The field currently produces both oil and gas. Until 1960, when the gas deliveries started to be made to El Paso under the temporary authorization, the field was operated solely for production of oil. Gas, as produced, was compressed and reinjected into the formation for the sake of maximizing oil production.

The Red Wash field now consists of 130 wells, including 7 wells used for injection of gas, 6 shut-in wells capable of producing dry gas, and two dry holes. Twenty-two miles of gas gathering and reinjection system pipeline picks up the wet gas after the oil is separated out in traps near the wellhead. The wet gas so gathered is processed and compressed at a central plant; concurrently some of the residue is being reinjected and some is being sold to El Paso under the contract basing this application.

Under the standard form 20-year contract between the producers and El Paso, the initial 18.5 cent price escalates one cent every five years, and is subject to periodic five year redeterminations based on future fair market value for the time being. The initial contract quantity to be delivered by Stancal and to be taken or paid for by El Paso is 11,250 Mcf per day, or approximately 4,100,000 Mcf per year. However, on any given day or days, El Paso has the option to take any desired amount between a floor of 7,500 Mcf per day and a ceiling of 15,000 Mcf per day.

The gas is pipeline quality, *i.e.*, dehydrated sweet gas, and is picked up by El Paso's lateral line at the tailgate of Stancal's processing plant at 960 pounds pressure. The field is sufficiently proved up so that Stancal could, and did in the contract, agree to furnish at least 82,125,000 Mcf of gas over the 20-year contract period. It is currently estimated that Red Wash contains a total of 182 million Mcf of gas; this estimate is, of course, subject to revision based on further exploration and development. When the pressure maintenance program is discontinued, additional volumes of gas will be made available to El Paso.

Geography and Geology. The Red Wash field is located in the Uintah Basin of northeastern Utah, bordered on the north by the Uintah Mountains, on the west by the Wasatch Plateau, and on the south by the Book Cliffs. In the wintertime roads to the Red Wash area, *e.g.*, U.S. 40 at 14,000 feet elevation, are sometimes blocked off by snow. There is but one town in the vicinity—the town of Vernal, Utah, population 3,655, to the northwest—"advertised as being the farthest city from a railroad in the United States" (Tr. 61). The Uintah Basin is very inaccessible, resulting in high expenses of gas and oil production operations, drilling, and maintenance.

Additionally, the geology and stratography of the Uintah Basin makes exploration and development difficult and risky. The gas-bearing sands are not found as continuous blanket deposits, but as lenticular stratographic traps, with sands which are (1) erratic, but generally low, in porosity and permeability and (2) of generally small reservoir content. Fractured shales are often encountered, and drilling often produces "crooked hole trouble" (Tr. 62). Based on geology as known to date, further drilling will be to 8,000 feet or more and will be undertaken on the likelihood of finding gas deposits rather than oil, if a strike is made at all.

Geologically, the Uintah Basin is a separate province, differing from the formations found elsewhere in Utah. Another such separate gas and oil producing province is the Paradox Basin of southwestern Utah, where, as a practical matter, exploration is based on the chance of finding oil. The stratigraphic conditions of the Uintah Basin "have very great similarities to the type of stratigraphic conditions under which production is found in the northeastern part of Colorado and the southwestern part of Wyoming" (Tr. 44), and, except for greater isolation, the geography of northwestern Utah is not dissimilar.

In general, because of geography and geology, Utah has proven through the years to be the most expensive, or one of the most expensive, onshore drilling terrains in the United States. Although hydrocarbon discoveries from exploration to date have not measured up to early expectations, the expert testimony is that the area has significant potential and should be further explored and developed. The Stancal experts also testified that a gas price in Utah somewhat higher than that prevailing in Colorado and Wyoming, and on the order of 20 cents per Mcf, would be required to induce producers to undertake the dry-hole risks involved in the development of the gas potential of the Uintah Basin.

Producers' Gas Markets. In distinction to other areas, notably "pipeline alley" of the Texas-Oklahoma Panhandle, alternative possibilities for connection of Utah gas are not extensive. The only major pipeline in the entire area is the

El Paso Pacific Northwest Division line, winding northward along the Utah-Colorado border from the San Juan Basin of New Mexico towards Wyoming and ultimately to Oregon and Washington.

The Utah Natural Gas Company, operating entirely within Utah, and a wholly-owned subsidiary of El Paso, brings gas from the Clear Creek field, 90 miles to the southwest of Red Wash, to Salt Lake City. From Exhibit No. 5, it appears that there are several good shut-in gas fields south of Red Wash, and it is said that there are plans to have Utah Natural connect this gas, for intrastate consumption, at 16.5 cents per Mcf at the wellhead (Tr. 151–152).

Colorado Interstate Gas Company, the nearest large pipeline complex, lies at least 150 miles to the east and to the north of Red Wash. See "Principal Natural Gas Pipelines of the United States," F.P.C. publication, 1960.

El Paso's situation with respect to gas supply for its Pacific Northwest Division is not one of urgent or desperate need, and, in principle, its contracting for new gas in the Uintah Basin should not be subject to the compelling upward price pressures which seem to motivate much of the *Catco* thinking. *Atlantic Refining Co.* v. *F.P.C.*, 360 U.S. U.S. 378. This conclusion is borne out by the practicalities of El Paso's negotiations for connection of the Westwater field to the south of Red Wash, discussed later in this opinion.

El Paso has run 8.9 miles of lateral line in a southerly direction from its mainline to effect the connection at the tailgate of Stancal's processing plant mentioned *supra*. This connection, authorized by approval of a "budget type" application, Docket No. G–20051, order issued February 2, 1960, 23 FPC 287, was made at a cost of $412,412. (See El Paso Natural Gas Company's report to the Commission of facilities constructed, filed March 27, 1961.) Had El Paso not made this connection and the contract now under consideration, it is difficult to see how or where Stancal could have sold the Red Wash gas for transmission to conventional consumers at any price.[1] There is certainly reason to speculate, and a permissible inference, that in the case of a market so drastically limited in outlet as the Uintah Basin, El Paso, for business reasons such as the continuation of exploration incentive, made a price to Stancal in excess of the distress price which might have been exacted.[2]

In any event, the initial overture looking towards purchase of the gas was made by El Paso's predecessor company in 1957, and bargaining began with 20 cents per Mcf asked, and 18 cents per Mcf offered. (Tr. 21.) As a result of arm's-length negotiations on price, delivery obligation, take-or-pay-for commitment, pressure, and other factors, agreement was reached on the terms digested above as of January 27, 1960, and deliveries commenced at the end of June, 1960. The record shows that the contract price, 18.5 cents per Mcf, was the fair market price for the gas. On the other hand, the record does not show that the producers are prejudiced, except in regard of profitability and consequent extra incentive to explore, by the 15 cents per Mcf price imposed by the Commission. Assuming that 15 cents per Mcf, or any price lower than the market price, is the *correct* price for the Red Wash gas, producer profit limitation

[1] Western Slope Gas Co., a wholly-owned subsidiary of Public Service Company of Colorado, is mentioned in the testimony herein, in addition to Utah Natural Gas Co. (*supra*). However, Western Slope operates entirely within Colorado and therefore is not a competitor of El Paso for out-of-state gas. See *Pacific Northwest Pipeline Corp.*, *supra*, 22 FPC at 118, 119.

[2] Stancal, protesting the 15 cent price limitation imposed by the Commission in its temporary authorization, *supra*, nonetheless connected the gas because of the "emergency situation requiring prompt commencement of deliveries from the Red Wash field." However, Stancal asked the Commission for, and was refused, an amendment of the authorization to provide for a 16 cent price. Petition to Amend Temporary Authorization, Docket No. CI60–333, filed May 16, 1960, and page 2 thereof.

resulting from the imposition of that price is simply a necessary consequence of Commission regulation in the public interest. See the governing principles of the common law, restated in *Munn* v. *Illinois*, 94 U.S. 113. The basic question remains: What are the principles on which we find the *correct* price for the Red Wash gas?

PRELIMINARY CONSIDERATIONS

In respect of the incidents of the sale of gas by producers to interstate pipelines, including the pricing of the gas, it may be said that *Phillips* [3] directed a change in the previous free economy of the open market, and contemplated a planned economy under Commission regulation. Phillips, however, did not structure (build the basis for) the operation of the planned economy in respect of producers. The structure was presumably that set forth by the Natural Gas Act. See *City of Detroit* v. *F.P.C.*, 230 F. 2d 810 (CADC), *cert.* denied 352 U.S. 829 reh. denied 352 U.S. 919. The Act, theretofore applied to "conventional" interstate gas utilities, after *Phillips* was to be applied to gas producers, *i.e.*, oil companies.

The incidents of the new planned economy inevitably go far beyond the derivation by the Commission of fair and reasonable prices for natural gas. For example (1) in respect of new gas coming on the market, unit price fixing at prices less than market value necessarily implies allocation of the gas, under Commission standards, in the usual case where the low-cost gas is sought by two or more interstate pipelines. (2) Exploration is, of course, in large part a function of profit potential; in the budgeting of oil company expenditures, there is competition for exploration money between various departments of the major companies. Cf. Tr. 49, 233–34. Therefore, to an undefined extent, Commission pricing must in advance plan for and allow for incentive to explore, particularly where the potential discovery is more likely to be gas than oil. (3) Overtures towards the standardization of gas sales contracts pursuant to Commission orders have already been made. *Notice of Proposed Additions to the Commission's Statements of General Policy* (etc.), Docket No. R. 200; *Non-Acceptability of Contracts* (etc.), Docket No. R. 199, both issued May 22, 1961.

In general, from the initial budgeting for exploration to final connection of new gas, the Commission necessarily will be involved in the previously private transactions of gas producers, as Commission regulation evolves towards firm price control.

By the time of *Catco* (cited *supra*), June 22, 1959, the Commission had not settled on a method of pricing gas within the frame of reference of the Natural Gas Act. The Commission has felt that framework to be inappropriate, and has called for new legislation. F.P.C. Annual Reports: 1955, p. 18; 1956, p. 19; 1957, pp. 25–26; 1958, pp. 15–16; 1959, pp. 18–19; 1960, p. 17. Meanwhile, gas prices paid to producers by interstate pipelines continued to rise rapidly. Alarm over the continued steep rise in prices for new gas on the prevailing sellers' market, and the absence of an effective plan by the Commission for price control, motivated the "strictures" [4] of *Catco*, as is evident from the Court opinion. However, the Supreme Court did not there direct that the planned economy for the gas aspects of the oil production industry should be based on the cost-of-service conventions of the public utility business in the regulation of pipelines under the Natural Gas Act. The net effect of *Catco* is a direction to the Commission

[3] *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672, decided June 7, 1954.

[4] Hastie, J., dissenting in *United Gas Improvement Co.* v. *F.P.C.*, 269 F. 2d 865, 869; reversed and remanded, 361, U.S. 195.

to hold the price line, while methods of price control are being worked out. This has been characterized as a "stop-gap device" with the "objective of providing simple, direct, and effective stop-gap protection for the consuming public." *United Gas Improvement Co.* v. *F.P.C.*, 283 F. 2d 817, 822, 823, (CA9), *cert.* denied, 365 U.S. 879 and 881.

Neither *Catco* nor subsequent court decisions specify with any degree of exactitude where the "price line" is, or what standards are to be used in its determination. The Commission has for present purposes clarified the problem of the correct approach to the price line by establishing "area rate levels" setting forth, *inter alia*, a schedule of initial prices for new gas connections under new contracts within specified geographical areas that are "convenient and well known," but "not necessarily in complete accord with geographical and economic factors which may be relevant," *i.e.*, geographical areas that are subject to revision. *Statement of General Policy No. 61–1*, 24 FPC 818, 819. Presumably, these initial prices will at some future time be set on the basis of the "reasonable financial requirements" of the oil industry and at levels "adequate to maintain the gas supplies needed by the consumers of the nation," but no higher than "necessary to accomplish that purpose." *Phillips Petroleum Co.*, 24 FPC 537, 547; appeal to CADC pending, No. 16175. Presumably, such future initial prices will be based on solid facts backing up a Commission determination of the correct price for new gas, replacing the solid facts of the marketplace (expressed in a negotiated price) as to the value of the gas.

For the time being, the Commission, lacking more exact standards, finds the correct price for given new gas on the basis of the existing finally certificated prices for other supply in the general area. See, *e.g.*, *Texaco, Inc.* v. *F.P.C.*, 290 F. 2d 149 (CA5); *Humble Oil & Refining Co.*, 24 FPC 191; *Natural Gas Pipeline Co. of America*, 24 FPC 222, 305; *Peoples Gulf Coast Natural Gas Pipeline Co.*, 24 FPC 1, 106, 323; see also other cases cited herein.

Finally, and most importantly, the "area rate levels" thus found, at least in respect of new gas such as is involved in the case at bar, are in no way necessarily related to "fair and reasonable" rate levels under any definition of that term. The area rate levels express the history of "open-market" prices at a given point of time in a given place. A record such as the one before the Commission in this case, under the area pricing policy, is properly devoted to a listing and comparison of existing gas prices for other transactions in the area, as deemed relevant by the parties to the record. In the very nature of the inquiry, it is impossible to determine from such other prices what is the "lowest possible reasonable rate consistent with the maintenance of adequate service"[5] for the Red Wash gas. The record in this case is devoid of specific evidence upon which such a reasonable rate could be determined; evidence in this regard is unnecessary at the present stage in the evolution of pricing policy, in which attention is focused on other area prices for similar gas.

Otherwise stated, the correct price criterion is a comparison of the value of and price of the Red Wash gas to El Paso, with the value of and price of other gas sold in the area. From this postulate, two conclusions follow:

1. Producer costs in respect of the Red Wash gas are irrelevant. The fact that the Red Wash "gas production is strictly a by-product operation," that "the gathering system and compression facilities were not constructed for the purpose of making the instant sale to El Paso," and that "very little capital has been invested for the specific purpose of finding, collecting, processing and compressing the natural gas involved in these proceedings" (Southern California

[5] *Catco*, 360 U.S. at 388, quoted with approval in *P.S.C. of New York* v. *F.P.C.*, 287 F. 2d at 150 (CADC).

distributors' Brief, p. 20) is of no significance. Only the result—comparative quality of the gas, comparative volume, comparative delivery point, comparative accessibility of the supply—is of significance.

2. Considerations of the price necessary to preserve and enhance the "incentive" of the producers to explore for and develop nautral gas resources are not given weight in the derivation of the proper initial price for gas, under current "stopgap" (*supra*) judging techniques. The extensive argument of Stancal (Br. 15–19, Reply Br. 6–8) for the maintenance of incentive to explore in the rugged, expensive areas of Utah is irrelevant to the only issue: comparability of the contract price with the allowable price, which is derived solely from previously accepted similar sale transactions.

PRICE COMPARISONS

In connection with the truism that the Commission's area pricing policy ultimately reflects *value of gas*, as established in prior, acceptable, open market transactions, a further truism must be kept in mind: that the value of given "packages" of gas varies widely. At opposite extremes, we may have a sale of small quantities of low Btu, low pressure, sour, inaccessible gas to be picked up by the pipeline at the wellhead on the one hand, and a sale of large quantities of high Btu, high pressure, pipeline quality gas delivered to a mainline on the other hand. Price adjustments should be made to reflect such variations. *United Gas Improvement Co.* v. *F.P.C., supra; Cities Service Gas Co.*, 14 FPC 134, 141, 146, aff'd. *sub nom Signal Oil & Gas Co.* v *F.P.C.* 238 F. 2d 771 (CA3), *cert.* denied, 353 U.S. 944; *Transwestern Pipeline Co.*, 22 FPC 391, 396–401; *El Paso Natural Gas Co.*, 23 FPC 369, 376.

In the case of Red Wash, the transaction involves some 4,100,000 Mcf annually (11,250 Mcf per average day) of 985 Btu pipeline quality gas at 900 pounds pressure, delivered at a central point in the field to El Paso's lateral connecting with the main pipeline. The reserves are estimated at 180 million Mcf, of which 82 million Mcf are covered by the present contract.

Staff presents sales from two fields, both in Utah, as a basis for price comparison. *First*, Staff cites sales from the so-called "Bar–X" field, southeast of Red Wash, on the Utah-Colorado border. These sales are of wellhead gas, as 500 pounds pressure, 1,000 Btu content, and at a price of 12 cents per Mcf. The contracts for Bar-X, entered into in 1957 and 1958, cover 2,331,000 Mcf of gas deliveries annually, per Staff estimate, or 1,756,267 Mcf delivered in 1959, per Stancal presentation. Stancal points out that El Paso must compress this 500 pound gas to 600 pounds for delivery into its mainline, and that under its contracts therefor, as the field pressure declines, El Paso must gather the gas at pressure as low as 100 pounds and supply the necessary compression.

Second, Staff cites sales from the Westwater field, lying west of Bar-X, in Grand County, Utah. These sales involve some 16 miles of gas transmission to El Paso's mainline, over a lateral constructed by the producers. *Oil, Inc. et al.*, 25 FPC 1178, Docket Nos. CI60–170 and CI60–171, issued June 20, 1961. Eliminating transmission costs borne by the producers and reimbursed by El Paso through a 5.5 cents per Mcf differential, the sales are at 12 cents per Mcf for wellhead gas, at 900 pounds pressure and of 900–985 Btu content. The contract, entered into in 1959, covers 3,240,000 Mcf (per Staff estimate) of gas deliveries annually. Stancal points out that during the six months of each year from October 1 through March 1, the gas will be of only 900 Btu content, and that average initial delivery volumes of 9,000 Mcf per day are expected to decline to as low as 3,000 Mcf per day within three to six years, at which time the annual volumes will be a little over one million Mcf. El Paso's total expense

for the connection of this supply was $8,933 for a tap on the mainline and a meter. *El Paso Natural Gas Co.*, 23 FPC 287, 288, filing of March 1, 1961, pursuant to paragraph (B) of order.

Stancal, in its Exhibit 2, presents sales from several fields in Utah, southwestern Wyoming, and northwestern Colorado as a basis for price comparison. The principal fields cited by Stancal, in addition to Bar–X and Westwater, are:

(1) The Aneth field in the Paradox Basin of southeastern Utah. Disregarding the "wash" transaction under which El Paso picks up the gas and processes it in return for revenues from liquids, and disregarding production by El Paso and its affiliate from the field, the Aneth sale involves some 34 million Mcf annually (93,000 Mcf per average day) of 950 Btu pipeline quality gas at 850 pounds pressure, delivered at a central point in the field, under contracts entered into at various dates in 1957, 1958, 1959, and 1960.[6] The sale is permanently certificated at a price of 17.7 cents per Mcf, under Commission-imposed reduction of the 20 cent contract price. *El Paso Natural Gas Co.*, 23 FPC 369, 371–373, 383, 391–393, affirmed *sub nom Texaco, Inc.* v. *F.P.C.*, 290 F. 2d 149 (CA5).

(2) Various fields, including Dry Piney, East LaBarge, Big Piney, and Hogsback, mostly in Sublette County, Wyoming. As to the East LaBarge field gas, it appears that delivery at 860 pounds pressure and in volumes of 6,000-8,000 Mcf per day of 950 Btu gas has been authorized at a price of 15 cents per Mcf at 14.65 psia (15.384 cents at 15.025 psia), reduced from the contract price of 16 cents. *Humble Oil & Refining Co.*, 24 FPC 191. El Paso paid $44,677 for pipe and appurtenances to connect this supply. Filing of March 1, 1961, pursuant to 23 FPC 288, *supra*. In a recent initial decision, other fields in the same area were price conditioned by reducing the 18.5 cent contract price to 15 cents at 14.65 psia (15.384 cents at 15.025 psia). *El Paso Natural Gas Co.*, Docket No. CP60–72; initial decision issued August 25, 1961.

(3) The South Rangely field of Rio Blanco County, Colorado. Rio Blanco is adjacent to Uintah County, Utah, and the South Rangely field is some 65 miles from Red Wash. In the case of South Rangely, 950 Btu gas at 860 pounds pressure, without daily obligated delivery, and with only 5,200,000 Mcf total proven reserves, was permanently certificated by the Commission at 16 cents per Mcf. *Pacific Northwest Pipeline Corp.*, 22 FPC 117. The decision apparently involved a sale at the wellhead, and only one connected well. However, the South Rangely "strike" was apparently immediately adjacent to the Pacific Northwest (now El Paso) mainline, subject to connection without investment in a lateral line. See Exhibit 5. Considering the above proposed comparisons in reverse order:

Analysis of Prior Certificated Sales. (1) The certificaiton of South Rangely at 16 cents is not controlling on the price for Red Wash gas. That certification was made July 23, 1959, prior to a number of court decisions reemphasizing the Commission's duty to hold prices for new gas at the lowest possible levels, and the decision was in effect, although not in words, repudiated in the *Humble* case, *supra*, 24 FPC at 193–194.[7] The arguments from the South

[6] The *availability* of this amount was, however, limited to a period ending in 1962, and will fall to 36,000 Mcf per average day in 1973. See public findings in Docket Nos. G–12580 and G–13862. The wide variation in availability of gas over the term of the contract disadvantages El Paso, and perhaps tends to equalize the volume differential between Aneth and Red Wash.

[7] The distinctions made in the *Humble* opinion are unconvincing. There is no reason, except a change towards stricter pricing, for the Commission's refusal to adopt the South Rangely price for the Humble sale to the same market. The blunt fact is that subsequent court action on many of the July–August 1959 Commission certifications makes the correctness of those certifications subject to grave doubt. See discussion in *Gulf Oil Corp.*, 23 FPC 664, 677 and footnote 13; *Panhandle Eastern Pipe Line Co.*, initial decision of July 11, 1961, 27 FPC 53 at 70, footnote 23.

Rangely certification were thoroughly presented by Stancal and Gulf in their motions seeking amendmnet of the temporary authorizations herein, in which motions applicants specifically asked for "at least" or "not less than" 16 cents per Mcf at 15.025 psia. Filings of May 16 and August 1, 1960, *supra*, note 2. The Commission denied the amendment.

The Commission by its condition and Stancal by connecting the gas have effectively renegotiated the Red Wash contract, *pro tem*, at a 15 cent initial price. That 15 cent price has no more or less intrinsic justification than the 18.5 cent negotiated price, in terms of a "fair and reasonable" price. In terms of an upward price change in the *status quo* the South Rangely certification is insufficient, in the light of the other prices discussed herein, to warrant that result.

(2) The various sales from Sublette County and Sweetwater County in Wyoming, partly considered in the *Humble* and *El Paso* (Docket No. CP60–72) decisions, *supra*, are of substantial weight in the derivation of the correct price for the Red Wash gas. Those sales involve gas (a) from nearby, similar territory in Wyoming (*supra*), (b) destined to the same market, and (c) of substantial quantities. Exh. 2, items 21–25, 33–47. Substantially all of the Wyoming gas is certificated at 15 cents at 14.65 psia, the price set in *Humble*, 24 FPC at 195. Since Utah, southwestern Wyoming, and northwestern Colorado gas is always priced and sold at 15.025 psia, Exh. 2 herein, and the use of the 14.65 psia pressure base in the *Humble* order is entirely unexplained, it may be assumed that such use was inadvertent, and an error not to be compounded by extension into the area of Red Wash now under consideration. Consequently, the correct price "line" indicated by the Wyoming sales is 15 cents per Mcf at 15.025 psia (14.63 cents per Mcf at 14.65 psia), as set out in the temporary authorizations herein.

(3) The sales from the Aneth field are disregarded in the determination of the correct price for Red Wash gas, because the Paradox Basin, the site of the Aneth field, is not part of the geographical pricing area in which Red Wash is located. Aneth gas moves to California over El Paso's southern system: price competition (Transwestern Pipeline Company) is involved. The Paradox Basin is in the northern part of a geological, geographical, and "shopping" area in which price standards are derived from the San Juan Basin of New Mexico. *El Paso Natural Gas Co.*, 23 FPC 369 (*supra*). True, Stancal's contract official seems to have given substantial weight to the Aneth Prices in negotiating the 18.5 cent price presently in question (Tr. 127). True, there is no reason to question, and every reason to accept, his judgment as to the bases and end-result of a fair bargain for new gas on the open market. But as the courts and the Commission have now made clear, the derivations of the contract official in this regard are irrelevant in the usual case where price comparisons within an area can be made by the Commission. Applying the "stopgap" technique, the correct price *pro tem* is to be based only on such comparisons.

(4) The Westwater sales, essentially at 12 cents per Mcf, involve gas soon to be of small volumes in respect of deliverability and in large part of subnormal Btu content. Adjustments necessary to make Westwater a standard of comparison for Red Wash would be impossible of calculation.

(5) The Bar-X sales of 500 pound pressure wellhead gas have been adjusted for gathering, processing and compression, by Stancal computations indicating a current cost to El Paso of: 12 cents per Mcf to the producers, 3.7 cents per Mcf for gathering and processing, and 2.3 cents per Mcf for compression, or a total of 18 cents per Mcf. However, Stancal's computations derive solely from two selected pages of a 1959 annual report filed with the Commission by El Paso's predecessor. Neither the computations nor the basis therefor were

substantiated by an El Paso or other competent witness. Costs incurred by El Paso in respect of Bar-X gas as computed for 1959 may or may not be representative on the one hand, or over-stated on the other.

Stancal's computations, for instance, make no allowance at all for the comparative cost of El Paso's laterals to Bar-X and Red Wash. The lateral to Bar-X cost $102,528. *Pacific Northwest Pipe Line Co.*, Docket No. G–10425, Exh. A to application. The Red Wash lateral, as we have seen, cost over four times that amount.

If new gas is to take a price based on an adjustment of a prior certificated price, as the Commission did in respect of the Aneth field gas, *supra*, the adjustment must be certain and precise. In the case at bar, all that can be said with certainty is that the Red Wash gas is worth more to El Paso than the Bar-X gas, a fact already reflected in the price differential resulting from open-market (value) negotiations, and now in issue.

Conclusion on Price Line and Area. Based on the evidence adduced herein as to geological, geographical, historical, marketing, and operating characteristics of the general region as presented in the record, it is found that the appropriate pricing area is northeastern Utah, northwestern Colorado, and southwestern Wyoming.

This area coincides with that proposed by the Southern California distributors, except for the omission of northwestern Utah, as to which this record contains insufficient evidence for the making of a determination. This area differs from that proposed by Staff, the California Commission, and PG&E, all of whom propose the entire State of Utah as a pricing area, because the Paradox Basin of southeastern Utah lies in an area of totally different characteristics.

In the pricing area thus determined, there is insufficient basis in the record for either raising or lowering the 15 cent level at which the Red Wash gas is currently being delivered. The Wyoming sales support this level as being the correct existing price "line." The Utah and Colorado sales do not require a different conclusion. The 15 cent price should therefore be established, *pro tem*, as the correct initial price for sales from Red Wash, pending "area" or other proceedings looking towards a solid basis in economic facts as to the derivation of a different price.

Other Issues

Aside from the question of the proper price "line," based on the evidence as to preexisting sales of gas, the following additional contentions are made:

1. *Take-or-pay-for Contract Provision.* The Southern California distributors contend that the present contracts contemplate 100 percent take-or-pay-for, and that the Commission should "adopt a policy, applicable generally throughout the industry, of cutting back take-or-pay-for provisions from 100 percent to 80 percent" (Br. 25). The contention is qualified by the recognition that *ad hoc* treatment, *e.g.*, limited to El Paso's contracts such as the one now in question, would result in discriminatory disadvantage.

El Paso's obligation to take gas is expressed on an annual basis (365 times average daily take of 11,250 Mcf), and that obligation is equal to the annual obligation of the producers to deliver gas. Consequently, the contract provides for 100 percent take-or-pay-for, notwithstanding the permitted daily variation in take between a floor of 7,500 Mcf and a ceiling of 15,000 Mcf, which provides a "swing" advantageous to El Paso, and the advantage of a five-year period allowed El Paso for make-up of undertakes.

In recognition of the take-or-pay-for problem, the Commission has, pursuant to the Administrative Procedure Act, issued its Notice of Proposed Rulemaking, providing, *inter alia*, for a rule that "the annual quantity of gas to be paid for

by buyer, if not taken, shall not be greater than eighty (80%) percent of the daily-contract-quantity multiplied by the number of days in the year." Par. 4A(5) of Docket R. 199, issued May 22, 1961.

The rule, if adopted, will of course, not have retroactive application to a contract such as the one here involved, entered between El Paso and Stancal on January 27, 1960. The rule will operate prospectively, and its effect will be felt equally by all producers entering into gas sales contracts.

As the Southern California distributors seem to recognize implicitly, the matter of standardization of take-or-pay-for clauses is not properly to be effected by *ad hoc* revision of such contracts as may be reviewed in formal hearings, because this would result in discrimination and unequal treatment. Standardization and cut back or take-or-pay-for quantities can only be accomplished properly when effected by general order of the Commission applicable to all producers similarly situated. There is no concrete evidence of specific harm to El Paso resulting from the provision for 100 percent take-or-pay-for in the contract here involved other than the asserted interest of all consumers in a general rule providing for an 80 percent factor. The contention, therefore, is disallowed.

2. *Proof of "Need" for Gas.* The California Commission contends (Br. 5–8) that the applications should be dismissed because El Paso has not proved that it needs the Red Wash gas. However, El Paso's need for new gas supplies to meet its rapidly expanding California markets is a matter of common expert knowledge of this Commission, publicly declared. *El Paso Natural Gas Co.*, 23 FPC 369, 476; *idem*, 23 FPC 213; *idem*, 22 FPC 900, 903–904; *idem*, 19 FPC 393, 394–397; *idem*, 16 FPC 1354, 1357.

Insofar as the Red Wash gas is destined to be served to the territory formerly served by Pacific Northwest Pipeline Corporation, rather than to the California market, "need" is demonstrated by the Commission's specific reservation of 30,000 Mcf, peak day, for the northwest territory, from gas otherwise needed in California. *Pacific Gas Transmission Co.*, 24 FPC 134, 140.

It may be noted that the California Commission's contention was not specifically advanced during the hearing, when it could have been answered with concrete evidence that El Paso still has the need for gas so recently and so often determined by this Commission. The current findings of the Commission in such recent cases, added to the evidence in the record (R. 168–169) amply demonstrate El Paso's market and need for the Red Wash gas. In the California Commission has any evidence or basis for contending otherwise, which is to be doubted, the matter should be advanced at a hearing rather than on brief.

3. *Cost of Service Evidence.* The California Commission contends (Br. 22) that "some" evidence as to the costs incurred in the production of the Red Wash gas is necessary in the determination of a proper initial price therefor in this proceeding, and that absent voluntary submission of such cost evidence, the Commission should either (a) require that such evidence be produced, or (b) deny the certificates. Reference to the some 17 items of information specifically requested by the California Commission shows that investment, operating expenses, allocation of these two factors between oil and gas production, and ultimately, return to the producers from the investment in the Red Wash unit, are the categories of evidence which that Commission deems necessary to complete this record. (Tr. 77–84, 326–330.) [8]

[8] The request, as made, was substantially for the issuance by the Examiner of a subpoena duces tecum for Stancal records. However, according to a ruling of the Commission, Examiners are not authorized to issue subpoenas. *East Tennessee Natural Gas Co.*, 23 FPC 629.

Evidence of producer costs has never been held by the courts to be necessary to the determination of initial prices consonant with the public convenience and necessity; the indications, beginning with *Catco*, are to the contrary. *Atlantic Refining Co.* v. *F.P.C.*, 360 U.S. 378, 388; *United Gas Improvement Co.* v. *F.P.C.*, 283 F. 2d 817, 823 (CA9), *cert.* denied 365 U.S. 831; *United Gas Improvement Co.* v. *F.P.C.*, 287 F 2d 159, 161 (CA10); *P.S.C. of N.Y.* v. *F.P.C.*, 287 F. 2d 146, 148 (CADC), *cert.* denied 365 U.S. 880; *Texaco Inc.* v. *F.P.C.*, 290 F. 2d 149, 157 (CA5).[9] The decisions make the reason clear: "cost" evidence to be meaningful would involve unduly complicated and lengthy proceedings delaying initial gas connections. Beginning with *Phillips*, it has been clear that the Commission is not going to require cost evidence, such as that sought by the California Commission, in rate cases, *a fortiorari* as to certificate cases. *Phillips Petroleum Co.*, 24 FPC 537; *Permian Basin Proceeding*, 25 FPC 614, Docket AR61–1, order of April 5, 1961.

On the basis that there is no rule or policy of the Commission or the courts requiring cost-of-service justification of proposed initial rates, and that there is a Commission policy to the contrary, the contention of the California Commission is denied. The Commission has adopted area price "lines," not cost-of-service, as the standard for judging the convenience and necessity of proposed initial prices. *Statement of General Policy 61–1*, and discussion, *supra*. Such price "lines," or ceilings, are a function of market history as to value of gas for the time being in given areas, and are totally unrelated to producer cost-of-service for given supplies of gas.

Formal Conclusions of Fact

(1) Each of the applicants listed in the caption hereof is engaged in the transportatin and/or sale of gas in interstate commerce for resale for ultimate public consumption and is, therefore, a "natural-gas company" as defined in the Natural Gas Act, and each of said applicants is an "independent producer" as defined in the Commission's Regulations Under the Natural Gas Act.

(2) The sales and deliveries of gas in interstate commerce by said independent producers involved in these proceedings, and the facilities therefor, are required by the public convenience and necessity, at a price (initial rate) of 15 cents per Mcf at 15.025 psia, and certificates authorizing such sales should issue to each of them in accordance with the terms of this Decision and Order.

Order

Wherefore, It Is Ordered, subject to review by the Commission, that:

(A) Certificates of public convenience and necessity hereby are issued to Standard Oil Company of California, Dorsey Buttram, George P. Caulkins, Jr., and Gulf Oil Corporation, for the sale as proposed of natural gas in interstate commerce for resale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, upon the terms and conditions of this order.

(B) As a condition to the authorizations herein granted, the initial price for the sale of gas as proposed to El Paso shall be 15 cents per Mcf at a pressure of 15.025 psia in substitution for the initial price provided for in the contracts and the producers shall file supplements to their filed rate schedules reflecting the 15 cent price.

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[9] In *Texaco*, the California Commission presented the same argument on brief, but the Fifth Circuit did not specifically deal with the argument, although ruling against it *sub silentio*.

(C) The certificates herein issued shall be accepted in writing, under oath, within 30 days from the date of issuance of this order.

(D) The certificates isued herein are not transferable and shall be effective only so long as each of the applicants continues the acts and operations herein authorized in accordance with the provisions of the Natural Gas Act and the applicable rules, regulations, and orders of the Commission.

(E) The grant of the certificates herein shall not be construed as a waiver of the requirements of Section 4 of the Natural Gas Act or Part 154 of the Commission's regulations thereunder, requiring the filing of rate schedules for the service herein authorized, and is without prejudice to any findings or orders which have been or hereafter may be made by the Commission in any proceeding now pending or hereafter instituted by or against the applicants.

ROBERT M. WESTON,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

UNITED GAS PIPE LINE COMPANY, DOCKET NO. CP62-208

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 11, 1962)

On March 5, 1962, United Gas Pipe Line Company (Applicant) filed in Docket No. CP62-208 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of new delivery points and the sale and delivery of natural gas to United Gas Corporation for resale and distribution, all as more fully set forth in the application.

Applicant proposes to construct and operate the following facilities:

(1) A 2-inch tap valve at approximate Milepost 100 at a point in Section 12, Township 3 North, Range 2 East, on Applicant's 30-inch South-to-North Louisiana line to serve the communities of Effie and Center Point, Avoyelles Parish, Louisiana;

(2) A 2-inch tap valve at approximate Milepost 109.23 at a point in Section 31, Township 5 North, Range 2 East, on Applicant's 30-inch South-to-North Louisiana line to serve the communities of Buckeye, Deville, and Holloway, Rapides Parish, Louisiana; and

(3) A 2-inch tap valve at approximate Milepost 111.64 at a point in Section 12, Township 5 North, Range 2 East, on Applicant's 30-inch South-to-North Louisiana line to serve the community of Hickory Grove, Rapides Parish, Louisiana.

United Gas Corporation will construct and operate the distribution systems in the various communities. The estimated gas requirements in Mcf at 14.9 psia are as follows:

	Annual	Peak day
First year	72,818	725
Third year	76,625	770

Applicant estimates that the cost of the proposed facilities will be $1,470, which will be financed from current working funds.

Pursuant to due notice, a public hearing was held in Washington, D.C., on May 29, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, United Gas Pipe Line Company, a Delaware corporation having its principal place of busness in Shreveport, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of January 20, 1952, in Docket No. G–216 (3 FPC 3).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce subject to the jurisdiction of the Commission, and the construction and operation thereof and the transportation and sale of natural gas by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities and the proposed sales of natural gas by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulation under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of said Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c)(1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, United Gas Pipe Line Company, to construct and operate the proposed facilities and to sell and deliver natural gas, as hereinbefore described, all as more fully described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4), and (e) of Section 157.20 of said Regulations.

(C) The facilities hereby authorized shall be constructed and placed in actual operation and the sales of natural gas authorized in paragraph (A) above shall commence, as provided by paragraph (b) of Section 157.20 of the Commision's Regulations under the Natural Gas Act, within one year from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

COASTAL TRANSMISSION CORPORATION, DOCKET NO. CP62-231

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 12, 1962)

On April 2, 1962, Coastal Transmission Corporation (Applicant) filed in Docket No. CP62-231 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction during the 12-month period commencing July 1, 1962, and the operation of field facilities to enable Applicant to take into its certificated main pipeline system natural gas which will be purchased from producers thereof, all as more fully set forth in the application.

The purpose of this budget-type application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplied of natural gas in various producing areas generally coextensive with said system.

The total cost of the proposed facilities will not exceed $1,500,000, with no single project to exceed a cost of $300,000, and will be financed from short term bank loans.

Pursuant to due notice, a public hearing was held in Washington, D. C. on May 31, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Coastal Transmission Corporation, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its opinion and order of December 28, 1956, in Docket Nos. G-9262 and G-9960 (16 FPC 118).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the facilities to take natural gas purchased from producers thereof as proposed by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinfater ordered and conditioned.

(5) Public convenience and necessity requires that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(6) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit on or before September 1, 1962, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization hereinafter granted, (d) the location of said project or project, (e) the actual final costs of said facilities, and (f) the names of the independent producers involved, together with the dates of the gas sales contracts FPC gas rate schedule numbers, and the docket numbers of the related producer certificate applications.

(7) The authorization hereinafter granted should be limited to construction during the 12-month period commencing July 1, 1962, and the total expenditures for facilities to be constructed thereunder should be limited to a maximum of $1,500,000 with no single project to exceed a cost of $300,000.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Coastal Transmission Corporation to construct during the 12-month period commencing July 1, 1962, the proposed facilities hereinbefore described, as more fully described in the application in this proceeding, and to operate such facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Coastal Transmission Corporation.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of said Regulations.

(C) Applicant shall submit, on or before September 1, 1962, a statement under oath showing by project: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization hereinbefore granted, (d) the location of said project or projects, (e) the actual final cost of said facilities, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts, the FPC gas rate schedule numbers, and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the 12-month period commencing July 1, 1962, and the total expenditures for facilities to be constructed thereunder are hereby limited to a maximum of $1,500,000, with no single project to exceed a cost of $300,000.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NORTHERN STATES POWER COMPANY, DOCKET NO. E-7035

SUPPLEMENTAL ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTGAGE BONDS

(Issued June 12, 1962)

By order issued May 24, 1962, in the above-entitled matter, the Commission authorized Northern States Power Company (Applicant) to issue and sell at competitive bidding $15,000,000, principal amount of First Mortgage Bonds, due 1992, subject to the provisions, among others, set forth in Paragraph (B) of that order, as follows:

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

Applicant, on June 12, 1962, filed an amendment,, pursuant to the requirements of the afore-mentioned Commission order, setting forth, among other things, that it proposes to accept, as providing the lowest annual cost of money to it, thee bid of Halsey, Stuart & Co., Inc. to purchase the proposed issuance of $15,000,000, principal amount of Bonds, for the price of 100.91% of principal amount, with an interest rate of 4⅜%.

The Commission finds:

(1) Applicant has satisfactorily complied with the requirements of paragraph (B) of the Commission's order issued May 24, 1962, in the above docket, and under the bid it proposes to accept for the Bonds, the price to be received by Applicant therefor and the interest rate thereof are reasonable.

(2) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purposes.

The Commission orders:

(A) The price to be received by Applicant for the proposed Bonds and the interest rate thereof under the bid referred to above are approved as reasonable.

(B) The proposed issuance and sale of Bonds referred to above, upon the terms and conditions and for the purposes specified in the application, as supplemented by the amendment referred to above, are hereby authorized subjct only to the provisions of paragraphs (A), (C), (D), and (E) of the Commission's order issued May 24, 1962 in the above docket.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. G–16842

ORDER AMENDING ORDER GRANTING RECONSIDERATION AND ISSUING TEMPORARY AUTHORIZATION

(Issued June 12, 1962)

On February 16, 1962, Applicant filed a motion requesting amendment of the temporary authorization issued herein on August 30, 1961. No party has opposed the motion. This matter stems from the certificate issued herein on May 12, 1959, by order accompanying Opinion No. 320, 21 FPC 653, which authorized, among other things, construction of some 158 miles of loop lines by Applicant along its Kinder-Portland pipeline. On March 27, 1961, Applicant filed a motion to amend the Opinion No. 320 certificate, averring that it had not constructed the authorized Kinder-Portland loop lines and instead desired authority to install additional compression facilities on its Delta-Portland pipeline. We set Applicant's motion to amend for formal hearing.

On June 23, 1961, Applicant filed a request for temporary authorization to install and operate the substitute Delta-Portland compressor facilities. On July 21, 1961, we denied the request for temporary authority. On August 4, 1961, Applicant field a petition for reconsideration of the denial. Granting reconsideration, on August 30, 1961, we issued temporary authorization pursuant to Section 7 of the Natural Gas Act subject to the condition, among others, of ordering paragraph (B) that:

> (2) The aforesaid facilities shall not be used as occasion to withdraw any greater volumes of gas from the Bastian Bay Field than those being withdrawn prior to the issuance of this order.

It is this restriction which Applicant now asks us to remove.[1] Our orders of July 21 and August 30, 1961, discuss the background of that restriction.

In its motion to amend Applicant avers that the maximum volume withdrawn from the Bastian Bay Feld and delivered into Applicant's system prior to issuance of our order of August 30, 1961, was 55,000 Mcf per day (delivered on April 18, 1961). Applicant also says that

> * * * experience has proved that the condition has imposed, and will continue to impose, a serious burden upon Tennessee and is detrimental to the public interest.
>
> This condition if continued in effect will result in drainage of the Bastian Bay gas, will result in higher cost for such gas and also seriously restrict Tennessee's ability to operate its system in the most efficient and desirable manner.

In support of these contentions Applicant states:

(1) Applicant is only one of four major interest owners in the Bastian Bay Field;

(2) A second major owner, Phillips Petroleum Company, is currently delivering its natural gas production to Southern Natural Gas Company;

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[1] Applicant's motion fails to describe this restriction precisely and its prayer for relief requests removal of "the condition contained in Ordering Paragraph (B) (1)"; but since Applicant fails to state any ground for removing condition (B) (1), and does present arguments germane to condition (B) (2), we construe the motion to amend as speaking to this latter condition.

(3) Applicant "is advised" that Tidewater Oil Company and Gulf Oil Corporation "contemplate substantially increasing deliveries to United Gas Pipe Line Company" under an existing gas purchase contract[2] "upon completion of United's new pipeline out of the field on or about March 1, 1962";

(4) The Commissioner of Conservation of the State of Louisiana has established production units and field rules for production of natural gas from the Bastian Bay Field by orders effective December 1, 1961. Basically, the followable production for the individual well units will be established as follows:

(a) the total field allowable production will be prorated among the individual well units on the basis of the number of productive acres contained within each unt;

(b) the allowable so granted to a well subsequent to July 1, of any year, not produced during the month granted, can be carried forward as unproduced allowable or 'under-production' which can be produced at a later time; however, if this accumulated underproduction is not produced prior to July 1, of the next succeeding year, this allowable is cancelled and lost for all time; and

(c) if such cancellation takes place "it necessarily follows that reserves are lost through drainage, which may result in irreparable economic losses to both the operator and to the land owners."

(5) "According to information received by Tennessee" the combined minimum daily take or pay for volume under the Tidewater and Gulf contracts with United Gas Pipe Line Company will be approximately 94,000 Mcf per day "when all production facilities are tied in"; and United's maximum take rights will equal 141,000 Mcf per day;

(6) Applicant owns approximately 60 percent of the acreage (in all sands) of the production units established in the Bastian Bay Field and must, therefor, be in a position to take into its system volumes approximately 150,000 and 320,000 Mcf per day in order to be able to match United's minima and maxima (if United take these volumes) or else suffer the threat of severe drainage;

(7) Applicant has a substantial monetary stake in its Bastian Bay leases, as shown in the proceeding in Docket No. CU61–106, and its unit costs are inversely proportional to the rate of production;

(8) Moreover, Applicant experienced several emergencies on its system last winter; should similar weather conditions fecur in the future similar "emergencies could be substantially alleviated were Tennessee permitted to take greater volumes of gas from the Bastian Bay Field."

We have examined the Louisiana Department of Conservation's Statewide Order No. 29–F,[3] which governs proration of nonassociated gas reservoirs in that State. Order No. 29–F provides, among other things, that:

(1) Nominations for allowables shall be filed "on or before the fifth (5th) day of March, June, September, and December of each year" and allowables shall be issued for each quarter of the year;

(2) "No gas well shall be entitled to an allowable, nor shall any allowable be granted, until all necessary physical connections are made to permit full utilization of the allowable to be granted"; and

(3) Any underproduction of the allowables "remaining on the 1st day of July of any year shall be cancelled and shall not thereafter be made up."

[2] See Tidewater Oil Company, FPC Gas Rate Schedule No. 108; Gulf Oil Corporation, FPC Gas Rate Schedule No. 214.

[3] Issued November 8, 1955, amended effective July 1, 1959, reported in Byram, *Rules and Regulations of the Louisiana Conservation Commission Oil and Gas*, Section I, pp. 18-19; and also in 5 *Oil and Gas Reporter* 474-8.

In the hearings held May 7 and 8, 1962, in Docket No. CP61-106 Applicant's witnesses testified that United had been withdrawing roughly 12,000 Mcf per day from three reservoirs in the Bastian Bay Field into an intrastate system pending completion of its interstate facilities; that those intersate facilities had not yet been completed and put into operation but migh be by he later part of May; and that the Bastian Bay Feld allowables for the second quarter of 1962 amounted to about 16,000 Mcf per day for Applicant, 16,500 Mcf per day for Tidewater and Gulf (combined), and 13,000 Mcf per day for Phillips.

The hearings on the permanent certificate application in this proceeding (Docket No. G-16842) have concluded and briefing is in progress. In our view, however, we retain power under subsection 7(c) of the Natural Gas Act to revise our temporary certificate of August 30, 1961, without awaiting decision on the record in this proceeding and without prejudices to such decision in this or any other proceeding.

The Commission finds:

It is necessary and appropriate to amend the temporary authorization, issued August 30, 1961, as hereinafter provided, in order to assure maintenance of adequate service.

The Commission orders:

(A) The order of August 30, 1961, in this proceeding is hereby amended by deleting therefrom ordering paragraph (B) (2), without prejudice to the decision and determination of this or any other proceeding.

(B) Ordering paragraph (A) above shall become effective from and after July 1, 1962.

ALABAMA-TENNESSEE NATURAL GAS COMPANY, DOCKET NOS. G-5471, G-11982, G-17218 AND G-19984

OPINION AND ORDER MODIFYING AND ADOPTING INITIAL DECISION OF PRESIDING EXAMINER, DETERMINING JUST AND REASONABLE RATES, AND PROVIDING FOR REFUNDS

(Issued June 13, 1962)*

Syllabus

1. *Deferring* decision on use of liberalized depreciation in computation of Respondent's income taxes and accumulated taxes in determination of its rate of return, Commission *states* that any change in its policy with respect thereto will be applicable to rates here prescribed from and after date of such decision. P. 1182.
2. As long as rate ultimately arrived at by the Commission does not pierce contract ceiling, route by which Commission reaches its destination is matter wholly beyond legitimate scope of service agreement. P. 1184.
3. Deviation from letter of service agreement discussed; Commission *finds* that where such service agreements expressly contemplate *ex parte* filings, rights of customers will be generally safeguarded by order assuring refund at least as great as customer would have been entitled to had rate increase contemplated by contract not been exceeded. P. 1185.
4. Commission *finds* subparagraph 3(a) unreasonable, unduly discriminatory, etc. since it requires that increases in suppliers' demand charge, properly

*Designated Commission opinion No. 360. Initial decision appears on p. 1202. Order issued July 30, 1962, staying effectiveness of paragraphs (C) and (D), 28 FPC 242. Order issued August 3, 1962, granting in part and denying in part application for rehearing; modifying opinion and dissolving stay, 28 FPC 273.

classified as demand costs, be recovered by Respondent solely through increases in commodity charge; *orders* limitations expressed therein be deemed inoperative and of no effect. P. 1186.

5. Commission uses test year concept for determining just and reasonable rates for each of three locked-in periods; *rejects* Respondent's requested use of each and all five years embraced by such periods; uses test years 1958 and 1959, but employs two-year interval, 1955 and 1956, for first period. P. 1187.
6. Use of single 3-day peak period for each test year is fair, reasonable and conventional basis for testing system capacity during test period and for allocating demand costs between jurisdictional and nonjurisdictional customers. P. 1187.
7. In determining prospective rates it is generally desirable to use most recent period of actual experience for test years because such data tend to be more realistic and representative for the future. P. 1187.
8. Amounts for rates of return stated in rate increase filings place no limitation on rates of return permitted Respondent. P. 1188.
9. Rates of return determined here for jurisdictional business are deemed necessary if jurisdictional business is to provide its fair share of return to which company is entitled; but Commission need not close its eyes to beneficial effects of industrial sales on Company's economic strength in evaluating its ability to finance operations. P. 1189.
10. Commission *notes* that over-all rate of return here found just and reasonable would bring a return on common equity of approximately 9.50 percent for prospective period. P. 1190.
11. Commission *concludes* that 6½ percent is a fair and reasonable rate of return for all dockets. P. 1190.
12. Respondent allowed to recoup through G–5471 rates the portion of unamortized rate case expense allocable to jurisdictional sales. P. 1191.
13. Commission *disallows* claimed court costs which are not known or reasonably predictable, but are speculative; *allows* proper regulatory expense to be spread over 8-year period. P. 1191.
14. Since it is re-examining issue of income taxes, Commission follows previous policy of permitting company to include in cost of service taxes computed on basis of straight line depreciation, while paying taxes on basis of liberalized depreciation; any policy change would be applied only prospectively. P. 1191.
15. Commission *allows* depreciation rate of 3.2 percent; *rejects* Respondent's request for 3.5 percent, subject to refund pending supplier's similar request. P. 1192.
16. "Merit increases," occurring after test year for prospective period, *disallowed* in cost of service. P. 1193.
17. Commission *agrees* that no deduction for depreciation on rights-of-way should be considered in determining Federal income tax allowance. P. 1193.
18. Commission *disallows* proposed increased rates tendered by Respondent under Section 4 of the Natural Gas Act; determines just and reasonable rates, and provides for refunds. P. 1195.

Stanley M. Morley for Alabama-Tennessee Natural Gas Company.

Reuben Goldberg, *George Speigel*, and *William L. Sharp* for Tennessee Valley Municipal Gas Association.

Samuel B. Ross, *Louis C. Kaplan*, and *Harwood G. Martin* for the Staff of the Federal Power Commission.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

SWIDLER, *Chairman:*

This is a pipeline rate case, involving increased rates filed by Albama-Tennessee Natural Gas Company (Albama-Tennessee) under Section 4 of the Natural Gas Act (Act). The company has made four successive filings for increased rates, the first in 1954, and the most recent in 1959 which are the rates presently in effect. All four of the rate increases in question were suspended by the Commission, and thereafter were collected subject to refund. The case before us therefore involves three so-called locked-in periods in which the rate increase covers a definite period in the past and the most recent increase which covers rates for the future.

The hearing on all four rate increases began on July 13, 1960 and was concluded on October 25, 1960. The presiding examiner's initial decision was issued September 25, 1961, and is before us on exceptions filed by Alabama-Tennessee and an intervenor, the Tennesse Valley Municipal Gas Association (Association).[1] The examiner would disallow some $515,000 of the approximately $1,481,000 collected by Alabama-Tennessee during the three locked-in periods and make comparable reductions for the future. Association's position is that the company's revenues collected subject to refund are excessive by some $718,000 for the locked-in periods. Commission staff's position in its brief is that Alabama-Tennessee had collected revenues exceeding proper costs by some $539,000 for the locked-in periods.

The issues were carefully considered and fully discussed in the findings and conclusions contained in the examiner's decision, which we adopt with modifications where appropriate. In summary we conclude that the examiner should have allowed the company higher rates of return which, with other adjustments we find proper, will, for the most part, yield the company slightly higher rates than those the examiner found just and reasonable but lower than those the company requested.

The Commission on June 1, 1962, ordered further briefs and argument on the issues of the treatment to be accorded the use of liberalized depreciation in the computation of Alabama-Tennessee's income taxes and of accumulated taxes in the determination of its rate of return. We are accordingly deferring a decision on these two issues with respect to Alabama-Tennessee's rates for the future until after the argument. However, it is not in the public interest to delay our decision on all of the other issues in these four dockets which will result in immediate refunds and rate reductions.

It should be noted that in the refunds ordered herein and the rates prescribed, we have based our treatment of these two issues upon certain prior Commission rulings which we are now re-examining. We approve the instant determination for the past periods involved and the interim until we reach a decision in these issues after a further argument because any change in Commission policy would not be made retrospectively. Any change in Commission policy on these issues will be applicable to Alabama-Tennessee's rates herein prescribed from and after the date of such decision.

FACTUAL AND PROCEDURAL BACKGROUND

Alabama-Tennessee is a small interstate gas pipeline transmission company extending from western Tennessee a distance of some 140 miles to Huntsville

[1] The Association represents resale customers of Alabama-Tennessee consisting of the cities of Corinth and Iuka, Mississippi; and Tuscumbia, Sheffield, Florence, Russellville, Decatur, Athens, and Huntsville, Alabama.

Alabama. It purchases its entire gas supply from Tennessee Gas Transmission Company (TGT), and sells gas for resale to 14 communities of medium size and to direct industrial customers. It has a gross plant in service of approximately $5,000,000 and its gross revenues amount to about $6,000,000 annually.

Alabama-Tennessee's four proposed increased rates in the four dockets listed in the caption were filed, according to the statements in the company's rate filings, to recover increases in the rates of its supplier, TGT. The cumulative amounts of the proposed increases on an annual basis and the periods of time to which the proposed increased rates relate are as follows:

Docket No. G-5471	$74,000	12/15/54 to 7/13/57.
Docket No. G-11982	$258,000	7/14/57 to 5/14/59.
Docket No. G-17218	$385,000	5/15/59 to 4/4/60.
Docket No. G-19984	$901,000	4/5/60 prospectively

The Association's Motion To Dismiss

As a threshold matter, the Association excepts to the examiner's refusal to grant its motion to dismiss Alabama-Tennessee's rate filings claiming the filings were not authorized by the service agreements between Alabama-Tennessee and its wholesale customers and, under the Supreme Court's decision in *United Gas Pipe Line Co.* v. *Mobile Gas Service Corp.*, 350 U.S. 332, must therefore be treated as nullities.[2] The Association contends that Alabama-Tennessee's right to file for rate changes is subject to the specific conditions set forth in subparagraph (a) and (b) of Section 3. In the Association's view, Alabama-Tennessee failed to meet those conditions in that it presented evidence at the hearing with respect to cost of service factors other than those referred to in subparagraphs (a) and (b), and also in that its proposed increases were not confined solely to the commodity charge, as allegedly required by subparagraph (a).

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[2] The pertinent provisions of Article V, Section 1, *et seq.*, of a typical service agreement, such as that applicable to sales to the Public Utilities Commission of the City of Corinth, Mississippi, provides as follows:

"1. The rates to be paid for natural gas delivered hereunder are subject to the jurisdiction of the Federal Power Commission and shall be those contained in Rate Schedule G-1 on file with the Federal Power Commission and lawfully in effect from time to time pursuant to the provisions of the Natural Gas Act.

"2. This agreement in all respects shall be and remain subject to the provisions of the applicable Rate Schedules and General Terms and Conditions attached to the rate schedules filed with the Federal Power Commission, all of which are by reference made a part hereof.

"3. Seller may file with the Federal Power Commission, or other body having jurisdiction, for a change in the rates and charges effective as to Buyer, in accordance with the following sub-paragraphs; provided, however, that should it hereafter become unnecessary for Seller so to file, Seller shall have the right to increase the rates and charges effective as to Buyer to provide that:

(a) One-half cent increase or decrease, as the case may be, *in the commodity charge* for *each full one-half cent* per Mcf that the *average cost* of gas purchased by Seller shall exceed or shall be less than the *average purchase price* paid by Seller for gas during the *calendar year of the effective date of the Rate Schedule* specified in Section 1 of this Article V. [Emphasis added in order to highlight the problematic features.]

(b) Adjustment of the commodity charge in an amount equal to the amount of any present or future sales tax levied by the United States or by the States of Alabama, Mississippi, or Tennessee, or any political subdivision thereof, on, or in respect of, applicable to, or measured by deliveries of natural gas hereunder to Buyer, if and to the extent any such sales tax shall be actually paid by Seller and in an amount equal to three-fourths of any additional tax, (as additional tax is defined in the next sentence hereof) which Seller shall be required to pay. * * *"

In most of the service agreements applicable to sales under rate schdule SG-1, the concluding phrase of subparagraph (a) is "during the calendar year 1949", instead of "during the calendar year of the effective date of the Rate Schedule specified in Section 1 of this Article V."

In reply, Alabama-Tennesseee urges, among other things, that its service agreements expressly permit it to file for rate increases reflecting increases in the rates of its supplier, TGT. It points out that each of its four rate filings was intended solely to pass on increased purchased gas costs, and that in each instance the increase in its demand or commodity charge was respective to an exactly equivalent increase in the demand or commodity charge of TGT. Alabama-Tennessee concludes that *Mobile* is inapplicable and that the issue is governed instead by the Supreme Court's later decision in the *Memphis* case, *United Gas Pipe Line Co.* v. *Memphis Light, Gas and Water Division*, 358 U.S. 103.

In denying the motion to dismiss, the examiner took the position that the provisions of Section 3 of the contract were not designed to limit the right to make *ex parte* filings, impliedly granted by Section 1, but were intended merely to establish an optional filing procedure, adherence to which would make it unnecessary for Alabama-Tennessee to file a full cost of service presentation. The examiner pointed out that the rate increases ultimately determined to be just and reasonable did not in fact exceed the increases in the average cost of purchased gas to Alabama-Tennessee.

Neither party offered for the record any explanation as to the reasons or surrounding circumstances which gave rise to the unusual requirements of subparagraph 3(a). Through an examination of the Commission's files, however, we have ascertained that Section 3 was a part of Alabama-Tennessee's initial form service agreement in 1949 and apparently was copied almost verbatim from the rate provisions of its then effective service agreement with TGT. The difficulties with which Section 3 bristles would appear to stem from the fact that a cost-reimbursement formula eminently appropriate in the case of a pipeline purchasing gas directly in the field became an anomaly when transplanted without significant modification to the service agreement of a secondary purchaser such as Alabama Tennessee.

Despite the indications that subparagraph 3(a) may have been the result of unimaginative draftsmanship rather than careful deliberation, the Commission is obliged to construe it consistently with its terms and in such a way as to give it a meaningful function when used incontext with other provisions of the contract. In so doing, we must disagree with the examiner's conclusion that the provisions of Section 3 should not be read as a limitation upon Section 1. Since Section 1, standing alone, would be deemed to endow Alabama-Tennessee with blanket authority to make *ex parte* filings, Section 3 would be reduced to surplusage unless construed as a qualification of that authority. The very least impact which must be ascribed to it is that filings which purport to be grounded solely on taxes or on increased purchased gas costs must conform to the specifications of the relevant subparagraph.

Alabama-Tennessee is alleged to have breached the service agreement in two ways: (a) by introducing at the hearing evidence with respect to cost of service items other than taxes and purchased gas costs; and (b) by filing proposed increases which deviated in certain respects from the formula contained in subparagraph 3(a). The first contention can be readily rejected. Section 3 imposes a ceiling upon the amount of the increase which the seller is authorized to propose, but places no limitation upon the cost of service data which it may adduce in support of that increase. Moreover, even if the contract had purported to impose such a limitation, it is clear that no agreement between the parties should be allowed to circumscribe the range of considerations which the Commission may, and indeed must, take into account in determining a just and reasonable rate. So long as the rate ultimately arrived at by the Commission does not pierce the contract ceiling, the route by which the Commission reaches

its destination is a matter wholly beyond the legitimate scope of the service agreement.

A more difficult question is whether the rate filings themselves were fatally defective and, if so, what consequences follow. Each of the four filings deviated in one or more respects from the formula prescribed in subparagraph 3(a). First, in Docket Nos. G–11982 and G–19984, increases in TGT's demand component were reflected by identical increases in Alabama-Tennessee's demand charge, rather than translated into "average cost" terms and added in that form to the commodity charge. Secondly, the proposed increases for the three locked-in periods duplicated each .1¢ increment, rather than merely each full one-half cent increment, in TGT's rate. Finally, in each filing the subtrahend utilized in computing the proposed increase was TGT's existing rate, rather than the "average purchase price paid by [Alabama-Tennessee] for gas during the calendar year" in which Alabama-Tennessee's existing rate schedule became effective.

In Docket Nos. G–5471, G–11982, and G–17218, the net effect of the above deviations was that the rate increases per Mcf of annual volume proposed by the applicant were actually less than those authorized by the subparagraph 3(a) formula. The only docket as to which the Association's *Mobile* argument has any real substance is Docket No. G–19984. In that docket the contractually authorized increases in the commodity charge was 6.5¢.[2] Alabama-Tennessee filed for an increase of 85¢ in its demand charge, which, for a customer having a 30% load factor (approximately the lowest load factor experienced by any of the company's G–1 customers), would be equivalent roughly to a 9.5¢ increase in the commodity charge. At 30% load factor, moreover, the increase we have determined to be just and reasonable, both for refund purposes and for the future, is more burdensome than the 6.5¢ commodity charge increase authorized by subparagraph 3(a). It is possible, therefore, that some of Alabama-Tennessee's customers may be prejudiced by its failure to adhere to the requirement that only the commodity charge be increased.

We do not believe, however, that this deviation from the letter of the agreement demands, or even justifies, the drastic relief requested by the Association, *i.e.*, dismissal of the filing and disallowance of all sums collected thereunder. It should be remembered that this is not a case like *Mobile* in which the contract, by providing for a fixed rate, impliedly ruled out any *ex parte* filings whatsoever. On the contrary, the instant service agreements expressly contemplate such filings, particularly for the purpose of passing on increased purchased gas costs. In these circumstances, the rights of the customers will be adequately safeguarded by an order which assures to each customer a refund at least as great as the refund to which it would have been entitled had the rate increase contemplated by the contract not been exceeded. Accordingly, we shall order that the amounts refunded to each customer in Docket No. G–19984 shall be the difference between the amounts collected subject to refund and the lesser of the following: (a) the amounts that would have been collected under the rates hereinafter found to be just and reasonable, or (b) the amounts that would have been collected had Alabama-Tennessee proposed and collected a commodity charge of 33.36¢ (representing 6.5¢ increase over the 26.86¢ charge

[2] This figure represents the margin (adjusted downward to the nearest ½ cent increment) between (a) 38.93¢, the average cost per Mcf of gas computed for the applicable test year (based on volumes for year ending 3/31/60 derived as follows: actual Mcf for calendar 1959 per FPC Form 2 minus actual Mcf for first quarter 1959 per application for increased rate plus estimated Mcf for first quarter 1960 per said application) at prices adjusted to reflect TGT's triggering rates; and (b) 32.24¢, the average cost, per FPC Form 2, for the calendar year 1959, the year in which the rates in Docket No. G–17218 became effective.

prescribed by the Commission in Docket No. G–17218) while holding its demand charge stable at 2.70 per Mcf.

As to the prospective period commencing with the effective date of this order, the Commission is neither required nor prepared to subordinate the rates it finds just and reasonable to the distorting demands of subparagraph 3(a). Section 5(a) of the Natural Gas Act, which applies to rates already in effect as opposed to rates subject to refund and awaiting Commission approval under Section 4(e), provides that whenever the Commission finds that a contract relating to rates, charges, or classifications is "unjust, unreasonable, unduly discriminatory, or preferential", it "shall determine the just and reasonable * * * contract to be thereafter observed and in force, and shall fix the same by order * * *". Section 4(e) of the Act authorizes the Commission, after a full hearing on a proposed rate change, to "make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective [*i.e.*, a Section 5(a) proceeding]". Taken together, these two provisions empower us, upon making the requisite finding, to order appropriate modification of the discriminatory language of the service agreement.

We have no hesitation in finding that subparagraph 3(a) is unreasonable, unduly discriminatory, and preferential. In substance, it requires that increases in TGT's demand charge, which are properly classified as demand costs, nonetheless be recovered by Alabama-Tenessee from its customers solely through increases in its commodity charge. In other words, Section 3 systematically discriminate against high load factor customers by requiring them to bear a disproportionate share of the costs incurred by Alabama-Tennessee in maintaining its peak capacity. We shall therefore order that the limitations expressed in subparagraph 3(a) in the form of service agreement of the tariff and in the executed service agreements shall henceforth be deemed inoperative and of no effect. Alabama-Tennessee may submit for filing in accordance with the Regulations under the Natural Gas Act superseding service agreements which are appropriate in light of our order deleting subparagraph 3(a).

The Justness and Reasonableness of Alabama-Tennessee's Proposed Increased Rates

Test Years

The Locked-in Periods. Alabama-Tennessee contends in its exceptions that the examiner erred in his selection of the test years 1955, 1958, and 1959 for the locked-in periods (exceptions, p. 6, *et seq.*). The Company broadly contends that in view of the vagaries of weather and fluctuations in revenue and costs the only fair and equitable test is to compare the revenues and costs of service during the entire five-year period from 1954 through 1959.

We reject Alabama-Tennessee's requested use of each and all of the five years embraced by the three locked-in periods for determining the company's just and reasonable rates for those periods. We conclude that it is reasonable and appropriate in this case to follow the examiner's method, which has received judicial sanction, and use the test-year concept for each of the locked-in periods. See *Michigan Wisconsin Pipe Line Company*, 18 FPC 407, affirmed. *Michigan Wisconsin Pipe Line Company* v. *FPC* 263 F. 2d 553 (CA6, 1959). This method will tend to some extent to minimize possible distortions resulting from nontypical sales and revenues for the years and partial years covered by such locked-in periods.[4] The claim of abnormally cold weather, and the asserted

[4] The rates of return earned during each month of the company's operations vary depending on the seasonal requirements of its customers and the company cannot reasonably expect to recover the same return consistently every month in the year.

need for further adjustments have not been sufficiently supported to justify the adjustments claimed.

However, Alabama-Tennessee's contention that the examiner erred in selecting 1955 for the test period for the first locked-in period in Docket No. G–5471 has merit. It appears that this early year does not afford a representative period for testing the rates for the entire 31 months in question. In lieu thereof, we have employed a two-year interval, years 1955 and 1956 (Exh. No. 34) for determining just and reasonable rates for this 31-month period which in our judgment provides a realistic, normalized period for testing the rates for the first locked-in period. For the two remaining locked-in periods we find the test periods employed by the examiner, as herein adjusted, to be reasonable and appropriate.

We also reject Alabama-Tennessee's exception to the examiner's use of three-day peak periods within each of the test years for determining the company's cost of service, instead of the company's average of the three-day sustained peaks occurring during the winter season at the beginning and at the end of each calendar year (exceptions, p. 49, *et seq.*) The use of a single three-day peak period for each test year, in accordance with the examiner's decision, is a fair, reasonable and conventional basis for testing the capacity of the system during the test period and for allocating the demand costs between jurisdictional and nonjurisdictional customers.

The Prospective Period. In determining prospective rates, it is generally desirable, absent weighty countervailing considerations, to use the most recent period of actual experience for the test year, because such data tend to be more realistic and representative for the future. The examiner used the latest available 12-month period ending March 31, 1960 as his test year. Alabama-Tennessee argues for an earlier test year, as adjusted by the company for the abnormally cold weather which it contends occurred. The claim of abnormally cold weather is not sufficiently supported to justify a change from the latest available data and we shall therefore adopt the examiner's test year for the prospective period.

Rate of Return

The presiding examiner found that Alabama-Tennessee should be allowed a 6 percent rate of return for the first and second locked-in periods, a 6.25 percent rate of return for the third locked-in period, and a 6.4 percent rate of return for the prospective period.

The staff did not file exceptions to the examiner's rate of return allowances. However, in its brief it recommended a maximum over-all rate of return of 6.25 percent for all dockets and periods except the prospective period, and a 6.50 percent rate of return for the latter. The Association, likewise, did not except to the rates of return determined by the examiner. In its brief the Association recommended over-all rates of return of 6 percent for each of the years 1955 through 1958, 6.158 percent for 1959, and 6⅜ percent for the future.

Alabama-Tennessee in its exceptions contends that the examiner erred on the rate of return issue in two principal respects.

First, Alabama-Tennessee contends, in essence, that the examiner erred in limiting the rates of return for the company to those stated at the time of its four successive rate increase filings.[8] The company argues that it is entitled to the rates of return said to have been justified at the hearing, rather than

[8] The stated rates of return were 6 percent in the application in Docket No. G–5471; 6 percent in Docket No. G–11982; 6.25 percent in Docket No. G–17218; and 6.5 percent in Docket No. G–19984.

those requested in its filings.[6] Also, the company contends that the fact that it filed for reimbursement for increases in the price of gas purchased from TGT does not justify any limitation on its rates of return.

Second, Alabama-Tennessee contends that the law and evidence require that it be given no less than a 10 percent return on the equity component of its capital structure. It states that we have allowed this much or more in all our recent decisions, to pipelines larger and more diversified than Alabama-Tennessee, and with greater bargaining power in the money market.

As to Alabama-Tennessee's first contention, we agree with the company that the amounts for rates of return stated in its rate increase applications place no limitation on the rates of return permitted it even though they are indicative of the company's views on these issues at the time of the filing. The principles governing what rate of return shall be allowed a utility have been stated by the Supreme Court in the *Hope* case cited below, and have been applied in numerous Commission decisions. The rate of return must be measured by the company's financial needs—by such matters as the "return to the equity owner" which "should be commensurate with returns on investments in other enterprises having corresponding risks", the return necessary to "assure confidence in the financial integrity of the enterprise," and to enable it to "maintain its credit and attract capital," in the language of the Supreme Court.[7] These are matters to be established by factual proof and if the evidence shows the need, the required rate of return is not to be limited by formal or procedural considerations of the kind referred to above.

The determination whether a given rate of return satisfies the aforementioned standards of the *Hope* decision is of course a matter of judgment. In the exercise of that judgment we consider all the relevant factors in each particular case.

One important factor we have relied on in determining a company's financial needs in relation to those of other companies has been a comparison of the earnings-price ratios of the several companies.[8] Staff's Exhibit No. 32 affords a sound basis for evaluating earnings-price ratios.[9] It contains, among other data, the earnings-price ratios of ten principal natural-gas pipelines from 1950 through 1959; of 15 natural-gas pipelines staff considered most comparable to Alabama-Tennessee in size and otherwise, from 1953 through 1959; and of Alabama-Tennessee from 1951 through 1959. Of course, data for the individual companies vary considerably. However, using straight averages, and confining attention to data from 1953 through 1959 for the 15 more comparable companies, the following facts taken from Exhibit No. 32 clearly show that Alabama-Tennessee has progressed to an increasingly favorable position in the eyes of the investor compared to other natural-gas companies:

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[6] As described in the examiner's decision, Alabama-Tennessee's evidentiary presentation was based on requested rates of return for the years and partial years embraced by each docket, varying from a low of 6.46 percent to a high of 7 percent for the prospective period.

[7] *FPC* v. *Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

[8] See, *e.g.*, *Southern Natural Gas Company*, 24 FPC 26, 29 (1960). Alabama-Tennessee's capital ratios for the years 1955 through 1959, including 1959 as adjusted to reflect the inclusion of new 6 percent bonds at an estimated cost of 6.10 percent, have been on the order of 60 percent (including deferred taxes) and 40 percent equity (Exhibit No. 33).

[9] As testified by staff witness McGrath, the earnings-price ratio establishes a guide as to the value investors place on the earning ability of a company. The earnings-price ratio is computed by dividing the current market price per share into the latest 12-month's earnings publicly available at the date of the market price.

	Average earnings-price ratios, 15 selected pipeline companies (percent)	Average earnings-price ratios, Alabama-Tennessee (percent)
1953	8.1	12.1
1954	6.8	9.1
1955	6.2	8.6
1956	6.7	7.3
1957	7.7	7.4
1958	7.3	7.3
1959	6.9	5.9

Alabama-Tennessee's presentation tends to discount earnings-price ratio as a factor in determining the proper rate of return, and further contends, citing *Corporation Commission of the State of Kansas* v. *FPC*, 206 F. 2d 690, 721 (CA8, 1953), that we must, in determining rate of return, consider a number of facts beyond that of the return to the investor, including such matters as the age of the company, its financial outlets, whether it is expanding or consolidating its position, and the like. Thus the company contends that it has operated for only ten years and has no supporting connections with other companies. It argues that it is subject to abnormal risks because it has little diversity in loads and its sales are subject to wide fluctuations because of the relatively high proportion of industrial sales made to only three customers under contracts that are subject to termination or may expire. It contends that a large part of its resale sales are made in Huntsville, Alabama, at the end of its line, and that if the federal government's Redstone Arsenal operation is relocated, these will be subject to cutbacks.

The record in these proceedings discloses, contrary to Alabama-Tennessee's claim respecting its operations, age, and abnormal risk, that the company is in fact a successful, profitable and seasoned utility enterprise. It has a record of consistent growth since 1951, when it began its operations, both in jurisdictional and nonjurisdictional business. It serves an area with a remarkable growth record and every prospect for continued growth.

Two other matters relating to this issue should be mentioned. The staff in its brief refers to "special circumstances" concerning Alabama-Tennessee, described in testimony by Mr. B. F. Grizzle, President of Alabama-Tennessee, on cross-examination that the company on its entire operation realized earnings on equity consistently in excess of 20 percent in the years 1951 through 1959. Staff argues that such high rates of return are due in part to the company's relatively high volume of direct industrial sales and to economies in operations due to its ability to sell gas from various points on its system after relatively short hauls. We have no jurisdiction over direct industrial rates and our methods of cost allocation are designed to exclude the related costs in fixing jurisdictional rates. Moreover, the rates of return we determine here for the jurisdictional business are those we deem necessary if the jurisdictional business is to provide its fair share of the return to which the company is entitled. Nevertheless, we need not close our eyes to the beneficial effects of such sales on the company's economic strength in valuating its ability to finance its operations. See, *e.g.*, Matter of *Mississippi River Fuel Corp.*, 11 FPC 288, 299 (1952). Nor can we ignore the fact that the lower return on equity for the prospective period is due to the cost of the recent bond issue, a substantial portion of which is intended for non-jurisdictional business.

A further factor to be considered is that, under four separate docket numbers, Alabama-Tennessee has been collecting revenues subject to refund since late 1954. In effect, the consumers have been contributing equity money, which

presumably will be replaced in part with debt when refunds are made. We are not here making the formal adjustments to reflect the abnormal equity portion of the company but note that for the prospective period such an adjustment would bring the return on common equity up to approximately 9.50 percent on the basis of the over-all return found just and reasonable herein.

It would thus appear from Alabama-Tennessee's increasingly favorable position in the eyes of the investor, its ability to finance successfully, and its low risk position, and from other facts in the record, that a fair and reasonable rate of return for Alabama-Tennessee for all four of the dockets in issue, is 6½ percent. Such rates of return will provide Alabama-Tennessee with a return on equity of 10.16 for 1955, 9.86 for 1956, 9.74 for 1957, 9.86 for 1958, 9.59 for 1959, and 9.25 prospectively, on the capitalization for each of those years which includes the reserve for deferred taxes at 1.5 percent cost.

Classification and Allocation of Costs

Alabama-Tennessee excepted to the examiner's classification of the costs of fuel, supplies and maintenance relating to compressor station equipment wholly to commodity and also to the examiner's allocation of customer costs between jurisdictional and non-jurisdictional customers. We reject Alabama-Tennessee's exceptions for the reasons stated by the examiner.

Costs of Service for the Four Dockets

One of Alabama-Tennessee's basic objections to the examiner's decision is his claimed failure to find and disclose the source of the costs of service from which he obtained his proposed rates, or to relate the costs of service to the rates found proper (exceptions, p. 1, *et seq.*).

Analysis discloses that the examiner relied essentially on staff's costs of service for the locked-in periods, and on the Association's cost of service for the future. We have used basically the same costs of service relied on by the examiner, drawing from the parties' cost of service where appropriate to obtain additional data or make necessary adjustments. The costs of service and adjustments we find proper for each of the four periods will be discussed separately below, and are shown in Appendices A through D to this opinion.

Regulatory Commission Expenses (All Four Dockets). Alabama-Tennessee excepts to the examiner's treatment of two items of regulatory Commission expenses. In Docket No. G–5471, Alabama-Tennessee sought to charge in each of the years 1955, 1956, and 1957, one-third of certain regulatory Commission expenses aggregating some $36,000 said to have resulted from earlier rate proceedings but not recovered by the company as of December 31, 1954. As the examiner recognizes, the unamortized average balance of such expenses have normally been treated as a part of a company's net working capital requirement allowable as a part of the rate base (ex. dec., p. 1212). The amortization of the remaining balance of the expenses is made by a monthly charge to operating expenses, in this case apparently $1,000 per month. However, the examiner held, *inter alia*, that since Alabama-Tennessee's rate case preceding this case was a settlement,[10] it must be assumed that such settlement was a compromise by all interests.

We are unable to agree with the examiner. The cost of service approved in the settlement referred to above[11] specifically provided for recovery of about

[10] The order settling that case was issued March 18, 1954 in Docket Nos. G–2253, *et al.*, 13 FPC 899.

[11] Docket Nos. G–2253, G–2336, 13 FPC 899.

$52,750 of unamortized rate case expenses, dating back to 1952, over a three-year period ending February 28, 1957. (Exhibits 58 and 59, Docket No. G–5471, *et al.*). By December 31, 1954, after 10 months amortization, an amount of approximately $38,100 should have remained under the terms of the settlement cost of service. Alabama-Tennessee claims $36,000.[12] After consideration of the settlement cost of service terms and the company's claim, we are of the view that the company should be allowed to recoup through the G–5471 rates the portion of the $36,000 unamortized rate case expense allocable to jurisdictional sales.

The company estimates the entire regulatory cost of the present four case at $75,000. The examiner concluded that some $30,000 of this total consisted of anticipated costs to Alabama-Tennessee in event of court review, but that Alabama-Tennessee should be allowed only $15,000 of such court review costs since at least half of such costs would relate to the effect of the rates upon nonjurisdictional sales as well as being in large part for the benefit of the stockholders in Alabama-Tennessee (ex. dec., p. 1212). The examiner would spread the $60,000 he would allow over an eight-year period at $7,500 per annum, which would distribute such costs evenly through the years 1955 through 1962 inclusive.

Alabama-Tennessee contends that there is no justification for the examiner's disallowance of $15,000 of the anticipated court review expenses in Docket No. G–19984 because it would not affect the company's nonjurisdictional rates, and also because the very purpose of these proceedings is to determine the dollars to which the company and its stockholders are entitled. Further, says the company, the examiner's disposition of this issue is inconsistent with his treatment of pre-1955 expenses. The company does not object, however, to spreading the regulatory expenses of these procedings over eight years, as the examiner proposes.

The Association, in contrast, excepts to the examiner's allowance of any of the $30,000 court costs claimed by Alabama-Tennessee (exceptions, p. 5, *et seq.*). The Association argues that no litigation may result from the instant order and that in any event the company's customers should not be required to pay for the company's attempt to overturn the Commission's order.

We conclude that the examiner erred in allowing any of the $30,000 claimed court costs. Alabama-Tennessee's claimed $30,000 court costs are not known or reasonably predictable, but are, on the contrary, speculative. Further, if the company does later commence litigation, the costs thereof would probably fall outside the period we rely on here for testing the company's rates for the future. Finally, any such costs of litigation would normally be recovered by the company in future proceedings. Accordingly, the $60,000 of regulatory commission expense allowed by the examiner should be reduced by a further $15,000 to $45,000. In the circumstances of this case, spreading this $45,000 evenly over an eight-year period, as provided by the examiner and not excepted to by any party, is reasonable.

Income Taxes (All Four Dockets). The Association excepts to the examiner's allowing in Alabama-Tennessee's costs of service Federal income taxes in excess of the amounts currently payable (ex dec., p. 1223, *et seq.*). As the Association recognizes, the examiner followed our previous policy, detailed in Opinion No. 326, issued on August 10, 1959, in *El Paso Natural Gas Co.*, 22 FPC 260[13] and in subsequent cases of permitting a company to include in its cost

[12] $35,998.50 of which $806.50 is chargeable to Docket No. G–5471.

[13] Opinion No. 326 was remanded on grounds which did not affect the validity of our decision on the liberalized depreciation issue. See *El Paso Gas Co.* v. *FPC*, 281 F. 2d 567 (CA5, 1960).

of service taxes computed on the basis of straight line depreciation, while paying taxes on the basis of liberalized depreciation, as permitted by the liberalized depreciation provisions of Section 167 of the Internal Revenue Code.[14] The Association requests that we reverse our earlier decisions and accept its position (exceptions, p. 7, *et seq.*). As stated at the outset of this opinion we are re-examining this issue but the examiner's treatment will be used for the purposes of this determination because any change in policy would be applied only prospectively.

Alabama-Tennessee excepts to the examiner's supposed treatment of regulatory commission expense for tax purposes (exceptions, p. 41, *et seq.*). We have adjusted the costs of service to reflect an actual payment of $5,625 each year for expense incidental to regulation of these dockets; thus the amount shown in the costs of service and the amount allowed for tax purposes would be identical. The same reasoning and treatment have been applied to our allowance of $36,000 of unamortized regulatory expense. Any adjustment shown on Schedule M of the tax return is thus irrelevant to the tax computation based upon our costs of service. The other minor exceptions filed by the company respecting income tax matters are likewise irrelevant or immaterial in light of the actions we take in this opinion.

Depreciation Rate (Last Three Dockets). Alabama-Tennessee excepts to the examiner's use of a depreciation rate of 3.2 percent rather than the 3.5 percent rate commencing July 1, 1957, proposed by the company. To justify the higher depreciation rate, Alabama-Tennessee claims that such an increase would be in line with the depreciation rate based on a 24-year remaining life claimed by TGT, Alabama-Tennessee's sole supplier. Alabama-Tennessee further contends that its depreciation rate should be increased because of the risks of its enterprise and the investment yet to be recovered through accruals of the depreciation expense charge. Stating that the change was the considered decision of its Board of Directors, the company points out that a 3.5 percent rate is used by other pipelines with the Commission's acquiescence in numerous cases (exceptions, p. 38).[15]

The examiner found, *inter alia*, that there is no evidence that TGT will be unable to supply gas 24 years hence, and that Alabama-Tennessee may acquire another source of gas long before that time. The examiner was also of the view that the question of changing Alabama-Tennessee's depreciation rate is not ripe for determination until TGT's comparable request is decided (ex. dec., p. 1214, *et seq.*).

We conclude that the examiner's decision should be affirmed on this issue, basically for the reasons stated in his decision and summarized above. As to Alabama-Tennessee's request that it be permitted to increase its depreciation rate to 3.5 percent subject to refund, pending determination of TGT's similar request, we cannot conclude, in view of all the circumstances, that Alabama-Tennessee's depreciation rate should be fixed at whatever depreciation rate may be subsequently permitted TGT. Accordingly, the costs of service attached hereto will show depreciation expenses computed at the 3.2 percent rate herein found proper.

Expense for Alternate Source of Gas (Docket No. G–5471). Alabama-Tennessee excepts to the examiner's elimination from the rate base in Docket

[14] We have used only the taxes currently payable in computing a tax accrual adjustment to the working capital allowance in the rate base (*cf.*, examiner's decision, p. 1223).

[15] It cites, *e.g.*, *Mississippi River Fuel Corp.*, 4 FPC 340, 344 (1945); *Gulf Interstate Gas Co.*, 12 FPC 116, 126 (1953); and *El Paso Natural Gas Co.*, 22 FPC 260, 265 (1959).

No. G–5471 of expenditures totaling $11,344, made in an effort to obtain an alternate source of gas from Texas Eastern Transmission Company (Texas Eastern). We agree with the examiner's disallowance of this item. The expenditures were incurred several years prior to the earliest test year employed in these proceedings and are of a non-recurring nature. Nor is there any basis for capitalizing them, *i.e.*, including them in the rate base subject to amortization over a period of years, since the expenditures produced no asset of any kind.

Normalizing Adjustments (*Docket No. G–19984*). Alabama-Tennessee excepts to the examiner's disallowance of $12,267 in increased wages and salaries which occurred after the test year for the prospective period. The company contends that these so-called "merit increases" were known and certain and should be allowed under Commission precedents.[18]

The examiner, following staff's position, concluded that the very use of the term "merit increases" indicates that its purpose was to reimburse employees for increased efficiency, which has the effect of reducing unit costs of labor for Alabama-Tennessee. Thus, citing data adduced by the Association, the examiner found that on a unit of sales basis, operating labor costs decreased during the period 1954 through 1959 from 2.374 cents to 1.70 cents per Mcf of gas, amounting to a reduction of approximately 28 percent in the unit cost of labor (ex. dec., p. 1218).

Merit increases are designed to reduce costs, not to increase them and the evidence of the company's tread of a decreasing unit cost of labor bears this out. The company has not sustained its burden of proof to add this item to the test year cost of service. See *Mississippi River Fuel Corp., et al.*, 4 FPC 340, 346–347.

Exclusion of Depreciation on Rights-of-Way (*Docket No. G–11982*). The Association excepts to the examiner's ruling that no deduction for depreciation on rights-of-way should be considered in determining the Federal income tax allowance (exceptions, p. 6, *et seq.*). The Association contends that the company should have claimed a deduction of $14,016, based on the holding in *Northern Natural Gas Co.* v. *O'Malley*, 277 F. 2d 128 (CA8 1960), that a taxpayer may claim depreciation on rights-of-way.

We agree with the examiner on this issue primarily because we believe the company was justified in refusing to litigate the relatively small amount involved (ex. dec., p. 1218).

Rate Design

Alabama-Tennessee renders service to only three classes of customers. (1) Under Rate Schedule G–1 (General Service), firm service is available over its entire system under a two-part rate providing for a monthly demand charge, and a commodity charge. (2) Under Rate Schedule SG–1 (Small General Service), firm service is available over the entire system under a straight rate (per Mcf delivered) to small customers only. (3) Under Rate Schedule I–1 (Interruptible-Industrial Service), interruptible service for resale for industrial use only is available to certain customers under a straight rate, as specified in the rate schedules.

Formerly, Alabama-Tennessee rendered service under a fourth Rate Schedule TPS–G–1, but such service was terminated April 30, 1956.

In general, we agree with the examiner's decision respecting the design of

[18] The company cites among other decisions, *Hope Natural Gas Company*, 3 FPC 150, 183, and *El Paso Natural Gas Company*, 22 FPC 260, 263.

the rates for the above classes of service and specifically as to his finding that maintaining the 45 percent load factor for the SG–1 rate will best serve the interests of Alabama-Tennessee and the customers it serves (ex. dec., p. 1218, *et seq.*).

We also conclude that ideally the maintenance of a two-cent per Mcf differential between the I–1 rate, which is a straight rate, and the commodity component of the G–1 rate is reasonable and proper. However, it is not practicable to maintain this differential in the rates prescribed herein because to do so would require an increase in the company's I–1 rate.

Concerning the TPS–G–1 rate in Docket No. G–5471, this rate was in effect only a few months in 1956, and only 488 Mcf of gas were sold under it. The examiner held, and we agree, that no action with respect to this rate is warranted (ex. dec., p. 1222, *et seq.*).

Prescribed Rates and Refunds

The costs of service we find proper for Alabama-Tennessee for each of the locked-in periods and prospectively are set forth in Appendices A through D attached hereto. Based upon those costs of service we shall prescribe as the just and reasonable rates for Alabama-Tennessee in the respective dockets the rates shown in Appendix E which also contains the rates proposed by the company and by the examiner for comparison.

In Docket Nos. G–11982 and G–17218, Alabama-Tennessee's proposed increases were filed on the basis of proposed increases filed by TGT in the latter's Docket Nos. G–11980 and G–17166. In the event we find TGT's proposed increases in those dockets unjust and unreasonable and require refunds by TGT, Alabama-Tennessee should be required to submit a plan satisfactory to the Commission providing for refunds to its jurisdictional customers of the appropriate portion of the amounts, including interest, it receives from TGT. Under such plan, the refunds by Alabama-Tennessee of the jurisdictional portion of the amounts received from TGT shall first be made to the G–1 and SG–1 customers to provide as far as practicable the 2-cent differential hereinabove found desirable between the commodity component of the G–1 rate and the I–1 rate.

As set forth in the examiner's decision, Alabama-Tennessee's proposed increased rates in Docket No. G–19984 reflect exclusively in the demand component an increase by TGT in Docket No. G–19983 of 85 cents per Mcf of billing demand. In the above prescribed rates we permit recovery of TGT's contingent rate increase in the demand component of Alabama-Tennessee's cost of service pending decision in G–19983. The prescribed rates follow the classified costs obtained under the Seaboard formula, except for the differential between the firm G–1 commodity rate and the I–1 rate previously described.

Alabama-Tennessee's proposed increased G–1 and SG–1 rates in Docket No. G–19984 were allowed to become effective subject to refund on April 5, 1960. Such rates as noted are based on increased rates charged by TGT in Docket No. G–19983, subject to refund. By order issued in Docket No. G–19983 on August 9, 1960, 24 FPC 204, under our interim order procedure, we disallowed a portion of TGT's proposed increased rates and directed refunds of amounts there found excessive, which refunds are not reflected in the cost of service shown in Appendix D hereto. Accordingly, Alabama-Tennessee should be required to file revised tariff sheets containing the rates we herein find just and reasonable as reduced to reflect the reduction in TGT's rates filed in accordance with our August 9, 1960 order. Likewise, Alabama-Tennessee should be required to

refund to its customers the amounts collected on and after April 5, 1960, in excess of the rates contained in the revised tariff sheets herein required to be filed, as further subject to the refund requirements set forth *supra*, in our discussion of the Association's motion to dismiss, all as more fully prescribed in our order hereto.

Alabama-Tennessee also should be required to submit a plan satisfactory to the Commission providing for refund to its jurisdictional customers of the appropriate portion, including interest, of any further refunds that may be made by TGT to Alabama-Tennessee in Docket No. G–19983 for gas delivered on or after April 5, 1960, as provided hereinabove for Docket Nos. G–11982 and G–17218. Respecting such refunds from TGT, Alabama-Tennessee shall compute appropriate further reductions in its rates in Docket No. G–19984, in the same manner as TGT's rate reductions are made, and file revised tariff sheets satisfactory to the Commission reflecting such reductions in its rates, maintaining to the extent practicable the 2-cent differential herein found desirable between the commodity component of the G–1 rate and the I–1 rate, as set forth hereinabove.

The rates herein prescribed in Docket No. G–19984 are also subject to possible adjustment to reflect the Commission's decision on the issues of the treatment of liberalized depreciation and return on deferred taxes which are the subject of further argument as provided in the Commission's order of June 1, 1962 herein.

The Commission orders:

(A) The decision of the presiding examiner issued on September 25, 1961, as modified herein, is adopted by the Commission as its decision in these proceedings.

(B) The proposed increased G–1 and SG–1 rates tendered for filing by Alabama-Tennessee in the respective dockets, as contained in its First Revised Sheets Nos. 5 and 10, Third Revised Sheet No. 5 and Second Revised Sheet No. 10, Fourth Revised Sheet No. 5 and Fifth Revised Sheet No. 10 and Fifth Revised Sheet No. 5 and Sixth Revised Sheet No. 10 to its FPC Gas Tariff, First Revised Volume No. 1 are unjust, unreasonable, unduly discriminatory and preferential or otherwise unlawful and are hereby disallowed.

(C) Alabama-Tennessee, within 45 days from the date of issuance of this order, shall file substitute tariff sheets, subject to approval of the Commission, containing the rates and charges set forth in the rate table in Appendix E, under the heading "Prescribed Rates" in Docket Nos. G–5471, G–11982, and G–17218. In Docket No. G–19984, Alabama-Tennessee shall file the rates and charges set forth under the heading "Prescribed Rates", but reduced to reflect the decrease in TGT's rates which were filed in accordance with our August 9, 1960 interim order.

(D) Alabama-Tennessee, within 45 days from the date of issuance of this order, shall refund to its customers for the respective period covered by each docket, the difference between the amounts collected in Docket Nos. G–5471, G–11982, and G–17218, under the increased rates tendered for filing in those dockets and the amounts that would have been collected in those periods under the "Prescribed Rates", to be filed under Paragraph (C) above, plus interest at the rate of 6 percent per annum from the date of payment to Alabama-Tennessee to th[illegible] [illegible]cess amounts so determined. In Docket No. G–[illegible]17 [illegible]mer, plus interest at the rate of 7 percent per annum shall be the differe[illegible] between the amounts collected in such docket and the lesser of the followin[illegible] (a) the amounts that would have been collected

Tax currently payabl[illegible]

under the rates filed in said docket pursuant to Paragraph (C) above, or (b) the amounts that would have been collected had Alabama-Tennessee proposed and collected a commodity charge of 26.86 cents per Mcf plus the average increase in cents per Mcf contemplated by Article V, Section 1, subparagraph 3(a) of its executed service agreements.

(E) Alabama-Tennessee shall submit a plan of refund to its customers, subject to the approval by the Commission, of the proportionate amount of any refunds, including interest it may receive from its supplier, Tennessee Gas Transmission Company, as a result of Commission determinations in Docket Nos. G–19980, G–17166, and G–19983 within 30 days from the date of receipt of such refunds by Alabama-Tennessee. The refunds to be so made are to be apportioned in the manner in which they are received from TGT; *i.e.*, in the demand or commodity components of the cost of service or in both if so received from TGT, and maintaining as near as practicable the 2-cent differential between the commodity component of the G–1 rate and the I–1 rate, as hereinbefore described.

(F) The rates filed in Docket No. G–19984 pursuant to paragraph (C) above shall be reduced to reflect any decrease in rates which TGT may be required to make by final Commission order in Docket No. G–19983 on a prospective basis subsequent to the end of the period for which refunds are made by TGT. Such rates shall also be subject to such appropriate further adjustment as may be required by the Commission's decision on further argument and briefs as provided by the order issued herein on June 1, 1962, but only from and after the date of such decision or a later date if specified by the Commission therein.

(G) Within 15 days after making of any refunds as provided herein, Alabama-Tennessee shall report to the Commission in writing and under oath the amount of refund made to each of its customers, showing separately the amount of principal and interest so paid and the billing determinants or other bases used for such determinations and shall serve a copy of such report upon each of the customers receiving a refund. Concurrently therewith, Alabama-Tennessee shall file with respect to such refunds, releases from its jurisdictional customers showing receipt of the principal and interest in conformity with this opinion and order.

(H) The limitations expressed in Article V, Section 1, subparagraph 3(a) of the form of service agreement contained in Alabama-Tennessee's FPC Gas Tariff, and in the executed service agreements thereunder, shall henceforth be deemed inoperative and of no effect. Alabama-Tennessee may submit for filing in accordance with the Regulations under the Natural Gas Act superseding service agreements which are appropriate in light of our order making inoperative the aforementioned subparagraph 3(a).

(I) The motion of the Tennessee Valley Municipal Gas Association to dismiss the proposed increased rates tendered for filing by Alabama-Tennessee in these proceedings hereby is denied.

(J) Exceptions not granted herein are hereby denied.

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APPENDIX A

Schedule 1

Cost of service—24 months ended Dec. 31, 1956

Line No.	Particulars	Combined cost of service		
		Total	Demand	Commodity
	(1)	(2)	(3)	(4)
1	Operating expenses:			
2	Production	$5,410,300	$1,826,600	$3,583,700
3	Transmission	350,400	169,100	181,300
4	Distribution	37,300	18,700	18,600
5	Customer accounting and collecting	32,500	16,200	16,300
6	Sales promotion	32,300		32,300
7	Administrative and general	294,900	133,400	161,500
8	Regulatory Commission expense	11,300	5,100	6,200
9	Total	6,169,000	2,169,100	3,999,900
10	Amortization of prior regulatory Commission costs	27,900	13,900	14,000
11	Depreciation	312,300	156,200	156,100
12	Taxes—other than income taxes	135,700	67,800	67,900
13	Total before return and income taxes	6,644,900	2,407,000	4,237,900
14	Federal income tax allowance	230,400	115,200	115,200
15	State income tax allowance	8,000	4,000	4,000
16	Total before return	6,883,300	2,526,200	4,357,100
17	Return at 6.5%	582,300	291,100	291,200
18	Total cost of service	7,465,600	2,817,300	4,648,300
19	Percent jurisdictional weighted average		[1] 62.8698	[1] 43.8808
20	Jurisdictional cost of service	$3,810,910	$1,771,200	$2,039,700
	Jurisdictional gas revenues			$3,876,200
	Jurisdictional cost of service			3,810,900
	Excess revenues			65,300

[1] Exhibit No. 35, table I, sheet I.

APPENDIX A

Schedule 2

Rate base, return and income tax allowance

Line No.	(1) Particulars	(2) 1955 and 1956 combined
1	Rate base:	
2	Gas plant in service	$8,586,000
3	Working capital requirement	514,650
4	Tax accruals adjustment—credit line 18	(141,850)
5	Total rate base	8,958,800
6	Return and income tax:	
7	Return at 6.5%	582,300
8	Deductions for tax purposes	(348,500)
9	Return after deductions	233,800
10	Tax at $^{52}/_{48}\times\$233,800$	253,300
11	Surtax exemption at $^{22}/_{48}\times\$50,000$	(22,900)
12	Federal income tax allowance	230,400
13	State income tax allowance at 3.46%×$230,400	8,000
14	Tax accruals adjustment:	
15	Federal income tax allowance—line 12	230,400
16	Deferred taxes—note 1	(28,900)
17	Tax currently payable	201,500
18	Tax accruals adjustment—note 2	141,850

Note 1: Accelerated and liberalized depreciation in the amounts of $22,049 for 1955 and $33,560 for 1956 at the 52% corporate tax rate.

Note 2: Assuming an average of 73.3333% and 68.3333% for the years 1955 and 1956, respectively, is available for working capital.

APPENDIX B

Schedule 1

Cost of service—12 months ended Dec. 31, 1958

Line No.	Particulars	Cost of service		
	(1)	Total (2)	Demand (3)	Commodity (4)
1	Operating expenses:			
2	Production	$3,655,000	$1,291,100	$2,363,900
3	Transmission	183,200	84,300	98,900
4	Distribution	21,000	10,500	10,500
5	Customer accounting and collecting	15,900	8,000	7,900
6	Sales promotion	20,800		20,800
7	Administrative and general	144,400	61,600	82,800
8	Regulatory Commission expense	5,600	2,400	3,200
9	Total	4,045,900	1,457,900	2,588,000
10	Depreciation	181,500	90,800	90,700
11	Taxes—other than income taxes	77,900	38,900	39,000
12	Total before income taxes and return	4,305,300	1,587,600	2,717,700
13	Federal income tax allowance	131,500	65,700	65,800
14	State income allowance	4,500	2,300	2,200
15	Total before return	4,441,300	1,655,600	2,785,700
16	Return at 6.50%	325,000	162,500	162,500
17	Total cost of service	4,766,300	1,818,100	2,948,200
18	Percent jurisdictional		76.4917	53.3557
19	Jurisdictional cost of service	$2,963,700	$1,390,700	$1,573,000

Jurisdictional gas revenue	$3,096,700
Jurisdictional cost of service	2,963,700
Excess revenue	133,000

APPENDIX B

Schedule 2

Rate base, return and income tax allowance

Line No.	(1) Particulars	(2) Detail	(3) Year 1958
1	Rate base:		
2	Gas plant in service		$4,782,400
3	Working capital requirement	$280,800	
4	Tax accruals adjustment—line 19	(63,100)	
5	Net working capital allowance		217,700
6	Total rate base		5,000,100
7	Return and income taxes:		
8	Return at 6.5%		325,000
9	Deductions for tax purposes		(193,000)
10	Return after deductions		132,000
11	Tax at 52/48 × $132,000		143,000
12	Surtax exemption at 22/48 × $25,000		(11,500)
13	Federal income tax allowance		131,500
14	State income tax allowance at 3.41% × $131,500		4,500
15	Tax accruals adjustment:		
16	Federal income tax allowance—line 13		131,500
17	Deferred taxes—Note 1		(23,400)
18	Tax currently payable		108,100
19	Tax accruals adjustment—Note 2		63,100

Note 1: Accelerated and liberalized depreciation in the amount of $45,100 at the 52% corporate tax rate.
Note 2: Assuming an average of 58.3333% of the tax currently payable is available for working capital.

APPENDIX C

Schedule 1

Cost of service—12 months ended Dec. 31, 1959

Line No.	Particulars	Cost of service		
		Total	Demand	Commodity
	(1)	(2)	(3)	(4)
1	Operating expenses:			
2	Production	$4,291,100	$1,405,000	$2,886,100
3	Transmission	188,600	88,700	99,900
4	Distribution	19,900	9,900	9,900
5	Customer accounting and collecting	14,200	7,100	7,100
6	Sales promotion	23,100		23,100
7	Administrative and general	178,800	77,700	101,100
8	Regulatory Commission expense	5,600	2,400	3,200
9	Total	4,721,200	1,590,800	3,130,400
10	Depreciation	177,000	88,500	88,500
11	Taxes—other than income taxes	85,800	42,900	42,900
12	Total before return and income taxes	4,984,000	1,722,200	3,261,800
13	Federal income tax allowance	150,400	75,200	75,200
14	State income tax allowance	5,100	2,500	2,600
15	Total before return	5,139,500	1,799,900	3,339,600
16	Return at 6.5%	342,500	171,300	171,200
17	Total cost of service	5,482,000	1,971,200	3,510,800
18	Percent jurisdictional		75.3789	53.9919
19	Jurisdictional cost of service	$3,381,400	$1,485,900	$1,895,500

Jurisdictional gas revenue	$3,427,900
Jurisdictional cost of service	3,381,400
Excess revenue	46,500

APPENDIX C

Schedule 2

Rate base, return and income tax allowance

Line No.	(1) Particulars	(2) Detail	(3) Year 1959
1	Rate base:		
2	Gas plant in service		$5,034,800
3	Working capital requirement	$301,500	
4	Tax accruals adjustment—line 19	(67,700)	
5	Net working capital allowance		233,800
6	Total rate base		5,268,600
7	Return and income taxes:		
8	Return at 6.5%		342,500
9	Deductions for tax purposes		(193,100)
10	Return after deductions		149,400
11	Tax at 52/48×$149,400		161,900
12	Surtax exemption at 22/48×$25,000		(11,500)
13	Federal income tax allowance		150,400
14	State income tax allowance at 3.41%		5,100
15	Tax accruals adjustment:		
16	Federal income tax allowance—line 13		150,400
17	Deferred taxes—Note 1		(23,400)
18	Tax currently payable		127,000
19	Tax accruals adjustment—Note 2		67,700

Note 1: $45,000 at 52%.
Note 2: 53.3333% of tax currently payable.

APPENDIX D

Schedule 1

Cost of service—12 months ended Mar. 31, 1960

Line No.	Particulars	Cost of service		
		Total	Demand	Commodity
	(1)	(2)	(3)	(4)
1	Operating expenses:			
2	Production	$5,089,900	$2,029,500	$3,060,400
3	Transmission	191,700	89,100	102,600
4	Distribution	21,400	10,700	10,700
5	Customer accounting and collecting	14,600	7,300	7,300
6	Sales promotion	24,900		24,900
7	Administrative and general	175,500	73,000	102,500
8	Regulatory Commission expense	5,600	2,400	3,200
9	Total	5,523,600	2,212,000	3,311,600
10	Depreciation	197,400	98,700	98,700
11	Taxes—other than income taxes	87,900	43,900	44,000
12	Total before return and income taxes	5,808,900	2,354,600	3,454,300
13	Federal income tax allowance	107,400	53,700	53,700
14	State income tax allowance	3,700	1,900	1,800
15	Total before return	5,920,000	2,410,200	3,509,800
16	Return at 6.50%	347,400	173,700	173,700
17	Total cost of service	6,267,400	2,583,900	3,683,500
18	Percent jurisdictional		76.46	56.07
19	Jurisdictional cost of service	$4,041,000	$1,975,700	$2,065,300

Jurisdictional gas revenues	$4,247,700
Jurisdictional cost of service	4,041,000
Excess revenues	206,700

APPENDIX D

Schedule 2

Rate base, return and income tax allowance

Line No.	(1) Particulars	(2) Detail	(3) Year ended Mar. 31, 1960
1	Rate base:		
2	Gas plant in service		$5,074,900
3	Working capital requirement	$311,200	
4	Tax accruals adjustment—line 19	(42,000)	
5	Net working capital allowance		269,200
6	Total rate base		5,344,100
7	Return and income taxes:		
8	Return at 6.5%		347,400
9	Deductions for tax purposes		(237,700)
10	Return after deductions		109,700
11	Tax at 52/48×$109,700		118,900
12	Surtax exemption at 22/48×$25,000		(11,500)
13	Federal income tax allowance		107,400
14	State income tax allowance at 3.41%×$107,400		3,700
15	Tax accruals adjustment:		
16	Federal income tax allowance—line 13		107,400
17	Deferred taxes—Note 1		(23,400)
18	Tax currently payable		84,000
19	Tax accruals adjustment—Note 2		42,000

Note 1: $45,500×52%.
Note 2: 50% of tax currently payable.

APPENDIX E

	Docket No. G-5471			Docket No. G-11982			Docket No. G-17218			Docket No. G-19984		
	Proposed rates	Examiner's rates	Prescribed rates	Proposed rates	Examiner's rates	Prescribed rates	Proposed rates	Examiner's rates	Prescribed rates	Proposed rates	Examiner's rates	Prescribed rates
Rate Schedule G-1:												
Demand per Mcf of billing demand	$2.70	$2.70	$2.70	$2.90	$2.70	$2.70	$2.70	$2.70	$2.70	$3.55	$3.48	$3.50
Commodity, per Mcf delivered	23.15¢	21.7¢	22.46¢	25.05¢	24.2¢	24.57¢	28.7¢	27.9¢	26.85¢	28.7¢	26.5¢	26.75¢
Rate Schedule SG-1:												
Per Mcf delivered	42.65¢	41.5¢	42.19¢	46.75¢	43.9¢	44.3¢	48.7¢	47.6¢	46.59¢	62.0¢	51.9¢	52.35¢
Rate Schedule I-1:												
Per Mcf delivered	25.1¢	25.1¢	25.1¢	25.1¢	25.1¢	25.1¢	28.3¢	28.3¢	28.3¢	28.3¢	28.3¢	28.3¢

DECISION

UPON APPLICATIONS FOR INCREASED RATES

(Issued September 25, 1961)

LAW, *Presiding Examiner:* On June 3, 1948, a decision was issued in the *Matter of Alabama-Tennessee Natural Gas Company* (Alabama-Tennessee), Docket No. G–585, authorizing the original construction of a pipeline system subject to the jurisdiction of this Commission, by a Hearing Examiner of this Commission. On July 2, 1948, thereafter the Commission adopted the said decision as its order with two modifications, one of which required the filing of a satisfactory tariff at least six months prior to the commencement of operations and the other of which required the beginning of construction within one year from the date of issuance of the Commission's order of July 2, 1948 [7 FPC 251].

Alabama-Tennessee thereafter constructed its interstate pipeline system in the manner authorized or as subsequently modified by virtue of later orders of this Commission. Alabama-Tennessee also filed its proposed tariff sheets as required by the Commission order of July 2, 1948. Such proposed tariff sheets of Alabama-Tennessee together with changes and modifications subsequently approved by this Commission constituted the tariff of Alabama-Tennessee which was effective on November 5, 1954.

On November 5, 1954, Alabama-Tennessee, pursuant to Section 4 of the Natural Gas Act and the Commissioner's General Rules and Regulations, particularly Part 154 thereof (CFR 18, Part 154), tendered for filing First Revised Sheets Nos. 5 and 10 to its FPC Gas Tariff, First Revised Volume No. 1. The tariff changes contained in the tendered filing, which were proposed to be made effective November 3, 1954, embodied a proposed annual rate increase estimated at $74,175, to compensate Alabama-Tennessee for an increase in cost of gas resulting from an increase proposed by its sole supplier, Tennessee Gas Transmission Company (Tennessee).

By order issued December 2, 1954, this Commission provided that, pending a hearing and decision thereon, the proposed rate and charges contained in the revised tariff sheet tendered for filing on November 5, 1954, should be suspended until December 15, 1954, and until such further time thereafter as they may be made effective in the manner prescribed by the Natural Gas Act. Notice was given to interested state commissions and others.

On January 7, 1955, the Commission authorized the tariff sheets tendered for filing on November 5, 1954, to become effective as of December 15, 1954, upon the filing by Alabama-Tennessee of a corporate undertaking to make such refunds to customers as the Commission might thereafter order upon such undertaking, together with 6 percent interest upon the amounts ordered refunded from the date of their collection and all costs of such refunding.

Subsequently on December 29, 1955, Alabama-Tennessee tendered for filing certain original sheets constituting Rate Schedule TPS–G–1 to its FPC Gas Tariff, First Revised Volume No. 1 providing for temporary firm peak service. By an order adopted January 25, 1956, and issued February 6, 1956, the Commission provided that the proposed TPS–G–1 rates of Alabama-Tennessee should become effective as of December 29, 1955, subject to the terms and conditions of the Commission's order issued January 7, 1955, in Docket No. G–5471, and subject to the terms and conditions of the corporate undertaking of Alabama-Tennessee filed pursuant to such order.

On January 14, 1957, Alabama-Tennessee submitted for filing Third Revised Sheet No. 5, and Second Revised Sheet No. 10 to its FPC Gas Tariff, First

Revised Volume No. 1, proposing increases in rates and charges expected to total approximately $184,000 per annum, based on estimated sales for the 12-month period ending July 31, 1957. Such proposed increases are in addition to the rates in effect subject to refund in Docket No. G–5471. Alabama-Tennessee alleged that the proposed increases are for the sole purpose of passing on to its wholesale customers their proportional part of the proposed rate increases tendered for filing by Tennessee on the same date (Docket No. G-11980), and required that its proposed filing be made effective on the date that Tennessee's proposed increases were permitted to become effective. Alabama-Tennessee proposed increases in its G–1 Schedule identical with those proposed by Tennessee. The proposed increase in the SG–1 rate schedule assumes a 30% load factor, based on experience.

On February 13, 1957, the Commission suspended the proposed rate increases of Alabama-Tennessee, proposed on January 14, 1957, until July 14, 1957, the same date on which Tennessee's proposed rate increase became effective and assigned Docket No. G–11982 to the proceedings thereon. The order in Docket No. G–11982 provided for a formal hearing upon the proposed increases, to be held at an undetermined future date. On July 18, 1957, the Commission issued a further order in Docket No. G–11982, providing that the increases proposed by Alabama-Tennessee, to which said docket number had been assigned, might become effective as of July 14, 1957, upon the filing within 15 days from the date of said order of a corporate undertaking by Alabama-Tennessee to make such refunds to all customers as the Commission might thereafter order, after hearing in the said matter.

On November 14, 1958, Alabama-Tennessee tendered for filing its Fourth Revised Sheet No. 5 (superseding Third Revised Sheet No. 5), Fifth Revised Sheet No. 10 (superseding Fourth Revised Sheet No. 10), and First Revised Sheet No. 11–D (superseding Original Sheet No. 11–D) to its FPC Gas Tariff, First Revised Volume No. 1. The changed sheets propose an annual increase in its rates and charges of $134,683 based on sales for the 12-month period ending September 30, 1958. Alabama-Tennessee stated that the proposed increases reflected only the impact of rate increases filed on the same date by its supplier, (Tennessee) and submitted a cost of service study, adjusted to show the increases in cost of purchased gas.

By an order of the Commission, issued December 12, 1958, in Docket No. G–17218, Alabama-Tennessee's First Revised Sheet No. 11–D to its FPC Gas Tariff, First Revised Volume No. 1, was permitted to become effective on December 15, 1958 and the other two proposed Revised Sheets were suspended and the use thereof deferred until May 15, 1959, being the same date on which the effectiveness of Tennessee's proposed rate increase was permitted. The said order also provided for a hearing at a date to be thereafter determined.

On December 22, 1958, Alabama- Tennessee filed a motion requesting that the Commission postpone the effective date of its First Revised Sheet No. 11–D to its FPC Gas Tariff, First Revised Volume No. 1, from December 15, 1958 to May 15, 1959. Alabama-Tennessee stated that such tariff sheet pertains to the sale of natural gas for resale for industrial use only and that it did not desire to collect an increased rate for such industrial gas prior to May 15, 1959, when Tennessee's increased rates may become effective in Docket No. G–17166. The Commission, by order issued on February 2, 1959, allowed the said First Revised Sheet No. 11–D of Alabama-Tennessee's to its FPC Gas Tariff, First Revised Volume No. 1 to become effective as of May 15, 1959.

On April 20, 1959, Alabama-Tennessee filed a motion requesting that the proposed revised tariff changes proposed in Docket No. G–17218 be made effective as of May 15, 1959. By order issued June 11, 1959, and amended by a further

order issued July 17, 1959, the Commission provided that the said Alabama-Tennessee proposed Fourth Revised Sheet No. 5, Fifth Revised Sheet No. 10, and First Revised Sheet No. 11–D to its First Revised Volume Sheet No. 1, should be effective as of May 15, 1959, upon the filing by Alabama-Tennessee of a corporate undertaking to make such refunds as the Commission might thereafter order in relation to the said Revised Sheets Nos. 5 and 10. The amended order of July 17, 1959 omitted First Revised Sheet No. 11–D from the requirement for the filing of a corporate undertaking, in view of the fact that the said First Revised Sheet No. 11–D related only to gas sold for resale for industrial purposes.

On October 5, 1959, Alabama-Tennessee tendered for filing Fifth Revised Sheet No. 5 and Sixth Revised Sheet No. 10, to its FPC Gas Tariff, First Revised Volume No. 1, proposing an annual increase in its rates and charges for jurisdictional sales of $515,941, based on sales for the year ending March 31, 1959. The proposed increase is based upon the rate-increase application filed by Tennessee, according to the rate-increasing application of Alabama-Tennessee.

By order, issued November 4, 1959, in Docket No. G–19984, the Commission suspended the said proposed Tariff Sheets, filed October 5, 1959, until April 5, 1960, and provided for a public hearing in regard thereto. On March 31, 1960, Alabama-Tennessee filed a motion requesting that the said proposed tariff sheets be made effective as of April 5, 1960. On May 20, 1960, the Commission issued an order making effective the proposed tariff changes requested in Docket No. G–19984 as of April 5, 1960, upon the execution and filing of a corporate undertaking within 15 days thereafter to make any refunds that might be directed thereafter by the Commission after a public hearing.

The corporate undertakings heretofore referred to in relation to proposed tariff sheets filed in Docket Nos. G–5471, G–11982, G–17218, and G–19984, have been duly filed. All of the proposed increased rates her under consideration are now being collected under them by Alabama-Tennessee.

On November 25, 1957, Tennessee Valley Municipal Gas Association (hereafter referred to as Municipal Association), filed a petition to intervene in Docket No. G–11982. The said Municipal Association described itself as an unincorporated association of municipally owned and operated gas distribution systems which are customers of Alabama-Tennessee. Subsequently the City of Corinth, Mississippi, the City of Florence, Alabama, the City of Tuscumbia, Alabama, and the City of Athens, Alabama, filed petitions to intervene in Docket Nos. G–5471, and G–11982. The cities of Corinth, Florence ,and Tuscumbia also filed petitions to intervene in Docket Nos. G–17218 and G–19984. In addition, the Town of Iuka, Mississippi, the Town of Selmer, Tennessee, and the City of Russellville, Alabama, filed petitions to intervene in Docket No. G–17218.

The Municipal Association filed a petition to intervene on November 25, 1957, in Docket No. G–5471, on April 27, 1959, in Docket No. G–17218, and on November 20, 1959, in Docket No. G–19984. In these petitions, the Municipal Association alleged itself to be an unincorporated association of municipally owned and operated gas distribution system, including the municipalities above named. In order to avoid duplication of effort in the hearing and to reduce the participants, the Commission denied intervention of the various municipalities and authorized the intervention of Municipal Association in Docket Nos. G–5471, G–11982, G–17218 and G–19984.

On May 19, 1960, the Commission issued an order consolidating these four proceedings and fixing July 12, 1960, as the date for the commencing of the

hearing thereon. By subsequent notice dated July 5, 1960, the date was postponed one day until July 13, 1960.

The hearing began on July 13, 1960 and continued through Friday, July 15, when a recess was taken until July 27, 1960. The hearing was reconvened on Wednesday, July 27, 1960 and continued through Saturday, July 30, when a recess was taken to Wednesday, October 19, 1960, in order to permit preparation of the direct cases of the Commission Staff and the intervener (Municipal Association).

The hearing reconvened on October 19, 1960 and continued through Tuesday October 25, 1960, when it was concluded. The original briefing schedule set by the Presiding Examiner at the close of the hearing provided for Alabama-Tennessee's main brief to be filed December 7, the brief of the Commission Staff to be filed December 28, the brief of Municipal Association to be filed January 5, 1961, and the final reply brief of Alabama-Tennessee to be filed January 19, 1961. At the request of Alabama-Tennessee the dates for briefs were later extended to December 21, 1960, January 17, 1961, January 26, 1961 and February 9, 1961, respectively. On January 23, 1961, counsel for the Municipal Association requested a further extension of briefing time from January 26, 1951 to February 16, 1961, and an extension of the time for the final brief of Alabama-Tennessee to March 9, 1961. This request of the Municipal Association was granted.

Subsequent to the filing of the final brief of Alabama-Tennessee on March 9, 1961, Municipal Association filed a motion for leave to file a supplemental brief, a copy of said brief being attached to the said motion. On April 3, 1961, Alabama-Tennessee transmitted to the Presiding Examiner a letter stating that it had no objection to the supplemental brief and commenting thereon. The said letter has been treated by the Presiding Examiner as a supplemental and final brief of Alabama-Tennessee, submitted in accordance with the procedural right of the party having the burden of proof in these consolidated proceedings to submit the last brief or substitute therefor.

The Interveners Motion to Dismiss

After the G–11982 rate was made effective under corporate undertaking in accordance with a Commission order of July 18, 1957, the City of Corinth attempted on August 19th to file an application for rehearing on the ground that the Commission had no jurisdiction to accept for filing the proposed rate increase. The application was rejected and the City of Corinth subsequently appealed to the United States Circuit Court of Appeals for the Fifth Circuit from the Commission's action in placing the increased rates in effect subject to refund. Corinth there asserted that it had a fixed price contract, and increases could not be authorized by the Commission.

The said Circuit Court of Appeals on June 29, 1959, held that the order from which the appeal was taken by the City of Corinth was interlocutory, procedural and ministerial, and did not go into the merits of the proceeding. The case is reported in 258 Fed. 2nd at page 10. Certiorari was refused by the Supreme Court on November 23, 1959, at 361 U.S. 900.

Early in the course of the hearing, Municipal Association moved to dismiss the four rate filings of Alabama-Tennessee here under consideration, upon the grounds that such filings were not authorized by terms of the contract between Alabama-Tennessee and the various distributors who are members of the said Municipal Association and represented thereby. The Presiding Examiner held that this motion should be considered only in connection with the determination contained in the initial decision.

Municipal Association argues that the Mobile case bars consideration of the present applications and that the exception to the Mobile case [1] created by the Memphis case decision [2] does not apply here. The argument of the Municipal Association is based on the fact that the question of price and rate schedules is discussed in two sections of the service agreement. The first of these provides that the rates to be paid for natural gas delivered thereunder is subject to the jurisdiction of the Federal Power Commission and are to be subject to the rate schedules on file with the Federal Power Commission and in effect from *time to time* pursuant to the provision of the Natural Gas Act. Undoubtedly, the first section standing alone would bring Alabama-Tennessee within the provisions of the exceptions stated in the Memphis case.

The Municipal Association's argument is that Section 3 of the same Article V relating to "Price and Rate Schedules" contains a subdivision which provided for the filing of an increase when there is an increase in the cost of purchased gas to Alabama-Tennessee justifying such increase but limits the rights of Alabama-Tennessee by requiring that the increase be requested only in the commodity charge. Another subdivision of Section 3 provides for an increase when the costs of Alabama-Tennessee are effected by changes in certain specified taxes. The tax question does not arise in the present group of proceedings. The provision in regard to increased cost resulting from higher costs of purchased gas reads:

> One-half cent increase or decrease, as the case may be in the commodity charge for each full one-half cent per Mcf that the average cost of gas purchased by Seller shall exceed or shall be less than the average purchase price paid by Seller for gas during the calendar year of the effective date of the Rate Schedule specified in Section I of this Article V *

It is not believed that the provisions of Section 3 of Article V, as this section appears in various service agreements filed under the G–1 and SG–1 rate schedules of Alabama-Tennessee, is intended to limit any of the rights of Alabama-Tennessee, as fixed by Sections 1 and 2 of the said Article. It is apparent that the provisions in regard to taxes and to increases in the "average" cost per Mcf of gas purchased by Alabama-Tennessee are intended to simplify the filing of rates increases in which the proposed increase is directly related to tax changes or to a change in the average cost of gas purchased by Alabama-Tennessee. To some extent, these provisions of the service agreement may (subject to Commission approval) simplify granting of increases, based upon either of the two reasons set forth in Section 3 of Article V by making it unnecessary for Alabama-Tennesse to present a full cost of service in justification of such an increase in rate.

Alabama-Tennessee's type of service agreement may also serve to facilitate agreements upon proposed increases or decreases, where no question appears other than those related to the increased cost of gas as a commodity or to a change in the tax or taxes referred to in subsection 3(b). The original form of the various applications for increase, which have been consolidated for hearing and are under consideration here, states that the proposed increases were to be based entirely upon increased cost of gas, as a commodity, to Alabama-Tennessee. When Alabama-Tennessee's evidence was presented, there were some other additional costs included, which did not represent cost of gas

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[1] *United Gas Pipe Line Company* v *Mobile Gas Service Corporation* 350 U. S. 332.

[2] *United Gas Pipe Line Company* v. *Memphis Light, Gas and Water Division*, 358 U.S. 103.

* In some service agreements, the final clause of subsection 3 (a) Article V reads "during the calendar year 1949".

to Alabama-Tennessee. These additions have been considered in the present proceeding. The rates which are hereafter developed for determining of refunds by Alabama-Tennessee to its jurisdictional customers for the periods covered by Docket Nos. G–5471, G–11982 and G–17218 do not in fact place upon Alabama-Tennessee's customers any additional burden of cost arising from any source other than increased rates which Alabama-Tennessee pays to Tennessee as increased average cost of gas as commodity. The same situation exists in regard to the rates developed in Docket No. G–19984, applicable to determination of both refunds and future payments.

The record does not indicate whether the provision of Section 3 of Article V of any service agreement originated prior to the agreement made in the consolidated proceedings in Docket Nos. G–2253 and G–2336 between Alabama-Tennessee and its customers, which the Commission ruled upon and approved March 18, 1954. If such a provision were contained in previous service agreements, their waiver at that time (if not accompanied by a specific reservation) would, it is believed establish a precedent and cut off any right which might otherwise exist by reason of the Mobile case, heretofore referred to. In this case, however, it is not believed the question of waiver is material since, under any circumstances, the average increased cost passed on, in each case, to the customers of Alabama-Tennessee is less than the average increased cost, per Mcf of natural gas, to Alabama-Tennessee.

Upon consideration of the motion by Municipal Association to dismiss the several rate increase applications of Alabama-Tennessee under consideration in these consolidated proceedings, it has been determined that the Municipal Association has not established any justification for granting of its motion. Accordingly, the said motion is hereinafter denied.

Rate of Return

In its application for a rate increase in Docket No. G–5471, filed November 5, 1954, Alabama-Tennessee asked only for a 6% rate of return. Subsequently when the case came to hearing Alabama-Tennessee presented exhibits asking for a rate of return of 6.46% for the year 1955, 6.59% for 1956 and 6.69% for the portion of the year 1957 which would be included in the locked-in period, as to which the proper rate is to be determined in Docket No. G–5471. In relation to Docket No. G–5471 the Staff proposed a rate of return of 6.25%. Intervener Municipal Association prepared their exhibits on the basis of a 6% return during the period for which rates are to be determined by the action taken in Docket No. G–5471. We will hereafter discuss the breakdown of the rates into yearly segments proposed by Alabama-Tennessee and the Staff. For the present it is sufficient to say that we find no sound justification for granting to Alabama-Tennessee a return higher than the 6% rate of return claimed by that company in its application in the said Docket No. G–5471.

In its application for a rate increase in Docket No. G–11982, filed January 14, 1957, and suspended by Commission action to July 14, of that year, Alabama-Tennessee again asked only for allowance of a 6% rate of return. In its exhibits presented during the hearing, Alabama-Tennessee sought a 6.69% rate of return for the portion of the year 1957 (for which a rate of return is to be determined in Docket No. G–11982) as well as a rate of return of 6.68% for 1958 and a 6.83% return for the portion of the year 1959 included within the locked-in period covered by Docket No. G–11982. The Staff of the Commission recommends an allowance of a 6.25% rate of return for the period for which rates are to be determined in Docket No. G–11982. The Intervener Municipal Association insists that Alabama-Tennessee was only entitled to a 6% rate of return during the period in question in Docket No. G–11982. While the

evidence indicated that a slightly higher rate (6.10% and 6.15%) might be justified by the higher cost of money which was actually experienced during the period covered in Docket No. G–11982, it would appear that a dangerous precedent might well be created by dealing with rate proposals on the basis of intervening historical experience rather than on the basis of the knowledge of the applicant and others, as such knowledge existed at the time of the filing of the application for a rate increase. For that reason, we are, in the present decision, finding the rate of return to be allowed Alabama-Tennessee for the period from July 14, 1957, when the rate sought in the application in Docket No. G–11982 became applicable under bond, and May 14, 1959, when a further increase in rate became effective under bond in Docket No. G–17218, should not exceed 6% which Alabama-Tennessee asked for in its application filed January 14, 1957 in Docket No. G–11982.

In the application filed November 14, 1958, in Docket No. G–17218 by Alabama-Tennessee for a rate increase, which said rate increase became effective under a corporate undertaking to refund excess rates as of May 19, 1959, Alabama-Tennessee asked for a rate of return of 6.25%. Alabama-Tennessee subsequently presented evidence in this proceeding claiming a rate of 6.83% for the portion of the year 1959 for which Docket No. G–17218 rates might be effective and a return of 7% for the portion of 1960 prior to April 5, 1960 when the rates suspended in Docket No. G–19984 became effective under a similar corporate undertaking. Both the Staff and the Intervener Municipal Association presented their evidence as to the portion of 1959 to which Docket No. G–17218 rates would be applicable on the basis of a 6.25% rate of return. The intervener also presented evidence as to the actual cost of service and cost allocation for the period from January 1, through March 31, 1960 on the basis of a 6.25% return. In this case (Docket No. G–17218) it appears that Alabama-Tennessee should also be limited to the 6.25% return sought in its application.

In the application in Docket No. G–19984, filed October 5, 1959, and subsequently made effective under a corporate undertaking as of April 5, 1960, Alabama-Tennessee sought a rate of return of 6.5%. The latest figures presented by Alabama-Tennessee on a prospective basis cover the 13-month period ending December 31, 1959, and claim a 7% return. A cost of service study, made on a prospective basis for the calendar year 1959 by Staff, provided for a 6.5% rate of return. This is the only cost of service study presented by the Staff which can be utilized for determining the action to be taken in regard to the rate increase application designated as Docket No. G–19984. The Staff recommends the 6.5% return utilized in their 1959 prospective-basis study as the rate to be made applicable to the period covered by the G–19984 rate, effective April 5, 1960.

The Municipal Association, in its cost of service exhibit on a prospective-basis for the 12-month period ending March 31, 1960, provided for a 6.375% rate of return. In order to do this the witness adjusted the prospective costs to show payment to Tennessee at the increased rates of Tennessee, collection of which, subject to possible refunding if found to be excessive in the pending proceedings in Docket No. G–19983, were made effective as of the same date when Alabama-Tennessee's rates became effective under a similar undertaking to refund any part of the increase subsequently found (in the proceeding in Docket No. G–19984) to be excessive.

The witness O'Neil in his testimony on behalf of Alabama-Tennessee and the brief of that company both claim support for the reasonableness of the 6.5% rate of return sought by Alabama-Tennessee in Docket No. G–19984 on the basis of the existence of securities issued by Alabama-Tennessee at 6% interest

and upon the company's claim to be entitled to a rate of return which will amount to 10% on the common stock equity. Witnesses presented by Staff Counsel and Municipal Association do not concede the justice of the company's claim to expect this rate of return upon the common stock, either as a matter of Commission policy or as a necessary basis for possible future attraction of equity capital.

While there is some indication that, because of its size, Alabama-Tennessee may be in less favorable bargaining position than larger companies, better known to the average buyer of bonds because of their more widely diversified operations and the fact that they are known to transport gas, which is ultimately distributed within those large cities where a large portion of the available investment funds of individuals and of corporations such as insurance companies, who are large buyers of pipeline bonds, are generally found. To what extent the apparent high cost of this money to Alabama-Tennessee results from its comparative small service area which covers parts of Alabama, Mississippi and Tennessee with but one resale customer listed in the last of these states, and to what extent this apparent high cost may result from the rather high percnetage of direct industrial business, can not be determined with certainty.

On the basis of Alabama-Tennessee's own allocation of the overall cost of service for the 12-month period ending December 31, 1959, less than 54% of the total gas sold was sold and delivered to jurisdictional customers and, on the basis of the double three-day peak demand[2] utilized by Alabama-Tennessee, less than 76% of the peak-demand gas went to jurisdictional customers on those days.

In Mr. O'Neil's exhibit No. 2, he lists the overall rate of return indicated to be anticipated or stated to be reasonable, in various Commission opinions or orders issued during the period from 1952 to 1960. The only one listed for the 1960 period is the decision in the Matters of Manufacturers Light and Heat Company, issued February 25, 1960. In that case, as in the present one, The Commission was dealing with 3 locked-in periods and one future period. The Commission there approved an agreement (not assented to by the Staff) on all other points, but with the rate of return left, by the customers, to the Commission for determination. Such objections as were raised by the Staff in the Manufacturer's case appear not to have gone to accuracy of data on costs, but to the fact that rate reductions would be entirely in the commodity element of rates, which would result in some deviation from The Seaboard formula, to the apparent relative disadvantages of small customers. The Commission's allowance there was a rate of 6¼% for the locked-in periods, which, taken together, extended from July 14, 1957 through November 30, 1959 and anticipated rate of return of 6½% for the prospective period beginning November 30, 1959. It should be noted in this connection that the return on common equity allowed for the locked-in period was less than the 10% which Alabama-Tennessee seems to consider a minimum requirement. In our study of the Commission's policy as to rate of return, consideration has also been given to two other decisions rendered by the Commission, subsequent to the presentation of the direct testimony of Mr. O'Neil. The most recent decision, which covers a period almost identical with that of the period involved in the prespective rate increase application in Docket No. G–19984, is the decision contained in an order of the Commission rendered March 20, 1961, in the case of Panhandle Eastern, Docket No. G–19780, 25 FPC 550. Consideration

[2] In its allocation exhibit, for the calendar year 1959 Alabama-Tennessee used an average of the 3-day periods of January 4, 5, and 6, 1959 and March 2, 3, and 4, 1960.

was given to that order because it shows some evidence of Commission policy as to rate of return. The effective date of the rates involved is March 26, 1960, ten days prior to the effective date of the rates involved in Docket No. G–19984. In that case (Panhandle) the Commission provided for an overall rate of 6.25%.

The other case to which consideration has been given, and of which we take notice as a matter of Commission policy, is that of Tennessee Gas Transmission Company (the sole supplier of Alabama-Tennessee) and the rate increases in question were those contained in the application in Docket No. G–19983, which is the very rate increase proposal upon which Alabama-Tenessee based its application for a rate increase in Docket No. G–19984. The period covered begins at the identical effective date applicable in Docket No. G–19984, to wit: April 5, 1960. The rate of return approved in that case (Docket No. G–19983), by the Commission's interim order, was 6⅛%, subject to future determinations as to accumulated deferred taxes and tax benefits for statutory depletion and intangible drilling expenses and to final determination on rate of return to be allowed for well-mouth production properties. Since Alabama-Tennessee produce no gas, the question of well-mouth production involved in the Tennessee case presents no problem here. The interim order in the Tennessee case (Dockt No. G–19983) was issued August 9, 1960, 24 FPC 204.

Alabama-Tennessee, in its 1959 Annual Report to stockholders, placed in evidence by reference, stated the earnings on its common stock ($1.00 par value) to be $1.37 per share in 1958 and $1.52 per share in 1959. While the cost of money has increased to some extent since 1954, the exhibits do not indicate an increase in such cost of magnitude sufficient to justify the return on investment which the Applicant now seeks. This is especially true as to the earlier rate increase requests here under consideration and we are somewhat surprised to find that Applicant's claim for return, presented by witnesses and alleged in its briefs, are in each case considerably in excess of the return sought by the application, filed seasonably by Alabama-Tennessee, at a time when the general nature and extent of the anticipated increased costs were known to it.

Upon a study of the whole record, we do not find the rates of return, proposed by Alabama-Tennessee in the first three applications under consideration here, to be unreasonable. We do not, however, feel that the evidence supports the claims of Alabama-Tennessee for the greater rates of return claimed by its witness during the hearing sessions and by its counsel in his briefs. Neither is it believed that the record justified the 6.5% return asked in the Docket No. G–19984 application. We do, however, as previously stated, believe that the record justifies an expected return of 6.4% to Alabama-Tennessee.

In considering proposed rates of return, as well as proposed rates, special consideration has been given to certain items of claimed investment and expenses, which are hereinafter discussed separately. Consideration has also been given to the Tennessee and Panhandle decisions hereinbefore referred to and to the cost of money statistics presented in evidence in this proceeding. A future rate of return of 6.4% does not appear unreasonable. The difference in results between the 6.4% and 6.5% rates of return amounts to between ten and eleven thousand dollars.

The Applicant's cost of service exhibits show varying rates of return for the various parts of the locked-in periods during which each of the proposed rates in Docket Nos. G–5471, G–11982 and G–17218 is to be applicable. Such fragmentation of the rates of return would be undesirable, even if it did not operate to provide rates of return greater than those which were sought in the applications. Certainly it appears undesirable here.

While the Staff has not varied its proposed rates of return within the period of applicability of any single rate proceeding here under consideration, it has applied the rate of return of 6.25% proposed in the Docket No. G–17218 application to the investment and working capital of Alabama-Tennessee for the prior years or parts of years to which the Docket No. G–5471 and Docket No. G–11982 proceedings are applicable. As previously stated, no justification for rates of return higher than those sought in the several rate increase applications has been shown by any party in the course of these proceedings.

Regulatory Commission Costs and Test Years

In the determination of operating expenses, Alabama-Tennessee, Staff Counsel and the Intervener are far from agreement in the item of regulatory commission expenses, which is recognized by each of the parties to be a part of the net working capital requirements which must be determined in arriving at the base upon which to determine the return allowable to Alabama-Tennessee in each of the several proceedings. Alabama-Tennessee arrived at this item, which is shown as part of the adjusted administrative and general expenses in each cost of service which it presented, by adding, to the actual amounts charged to deferred expenses in Account 146 for this purpose in each year, one-fifth of the estimated total expenses of the present group of proceedings, less such amounts as were actually charged to regulatory commission expenses during each period of a calendar or other year, for which a statement of overall cost of service was presented by its witness. In addition, it proposes to charge in each of the years 1955, 1956, and 1957, one-third of such unamortized regulatory commission expenses from earlier rate proceedings as it is now claimed that had not been recovered by Alabama-Tennessee as of December 31, 1954.

In its exhibits, Alabama-Tennessee presented overall cost of service studies and allocation thereof, on an actual basis, for the calendar years, 1955, 1956, 1957 and 1959. In addition Alabama-Tennessee presented a similar overall cost of service and an allocation thereof on a prospective basis for the calendar year 1959 adjusted to show estimated increased costs which would have resulted from the proposed increased rates if Tennessee's rates applied for in Docket No. G–19983 had been applicable during this period, as well as the estimated wage increases and additional personnel for which Alabama-Tennessee claims reimbursement in its application in Docket No. G–19984.

Subsequently, at the request of the Presiding Examiner, Alabama-Tennessee presented similar cost of service and allocation studies broken down to show actual cost for the period from January 1, through July 13, 1957 during which the G–5471 rates are to be applicable and for the period July 14, through December 31, 1957 for which rates may hereafter be fixed in Docket No. G–11982 would be applicable. A similar breakdown for the calendar year of 1959 was prepared and presented by Alabama-Tennessee, exhibits being presented to show the overall cost of service and allocation thereof separately for the period of January 1 through May 14, 1959 to which rates to be determined in Docket No. G–11982 are to be applicable and for the period May 15, through December 31, 1959, for which period the rates are hereafter to be determined in Docket No. G–17218. In addition, Alabama-Tennessee presented an allocation of the overall cost of service for the calendar year 1959, adjusted to give effect for the full year to the rates made effective under bond as of May 15, 1959 in Docket No. G–17166 of Tennessee and G–17218 of Alabama-Tennessee.

The Commission's Staff presented a cost of service exhibit, which was broken down by calendar years, with two additional sets of cost of service figures. The first of these additional sets was for the 12-month period ending June 30, 1957 and the other was a modified cost of service study for the year 1959, on a

prospective basis, showing costs as they would have existed for the year 1959, if the future known cost increases had been made applicable to the 1959 volumes purchased as well as to the other items of claimed increased expenses which were set out in the application in Docket No. G–19984. In presenting the Commission Staff's showing of cost of service for the various periods named above, the item of regulatory commission expenses is limited, in each case, to a much smaller amount than that claimed by Alabama-Tennessee and does not include any allowance for current rate case expenses or for similar expenses in previous rate cases claimed to remain unamortized on the books of Alabama-Tennessee as of December 31, 1954.

In spite of the previous request made to Alabama-Tennessee upon the record by the Presiding Examiner, the Commission Staff did not present breakdowns for the years 1957 and 1959 between the periods for which different rates are proposed to be made applicable, as a result of anticipated action of the Commission fixing both the time when each of the proposed rates would become effective under bond, such dates being the dates from which such rates as may hereafter be fixed in each of the consolidated rate proceedings will be effective.

The Intervener presented cost of service and cost allocation exhibits for the calendar years 1955, 1956 and 1958 on an actual basis. In addition, the Intervener presented an exhibit broken down for the year 1957 to separately show the cost of service and the allocation thereof for the period January 1 through July 13, 1957 and for the period from July 14 through December 31, 1957. The Intervener also presented a cost of service and cost allocation for 1959, showing separately such costs of service and the allocation thereof for the period from January 1 through May 14, 1959 and for the period May 15 through December 31, 1959. The Intervenor further presented cost of service and cost allocation studies on an actual basis for the 3-month period from January 1 through March 31, 1960, and for the year ending March 31, 1960, on a prospective basis with gas purchases at Tennessee's Docket No. G–19983 rates.

The Intervener would apparently allow, in the first three years, the regulatory commission expense from previous rate cases, which was claimed by Alabama-Tennessee. The Intervener would not, however, allow the costs of the present proceedings as part of the annual expenses during the years prior to Commission action, but would postpone their recoupment by Alabama-Tennessee until the future period. This would have the effect of making them collectable only from customers paying under the Docket No. G–19984 rates which are determined here. We cannot find this to be equitable.

Alabama-Tennessee's estimate of the regulatory cost of the present four cases is $75,000. Admittedly, some part ($25,000 to $30,000) represents anticipated cost to be incurred by Alabama-Tennessee in review of these proceedings by the courts after completion of the determination to be made by the Commission. It appears desirable to allow Alabama-Tennessee only half of the $30,000 or $15,000 of the possible court costs plus the $45,000 estimated as costs of these proceedings and to spread the estimated costs of the proceedings (reduced to a rounded figure $60,000) over an eight year period at $7,500 per annum, which would carry such costs evenly through the years 1955 to 1962 inclusive and distribute them among customers under all four proceedings . The reduction of $15,000 is based upon our belief that to the extent of at least 50%, any proceeding for review upstairs will relate to the effect of the rates which may be developed by the Commission, upon the direct sale rates of Alabama-Tennessee and upon the level of industrial gas costs generally, as well as being in large part for the benefit of the stockholders of Alabama-Tennessee.

The Staff has proposed separate and various rates for the portions of the applicable period of each of the locked-in rate proceedings coming within differ-

ent calendar years. While such a practice appears to have been followed in a few previous cases involving other pipeline companies, there is nothing in the record to indicate its desirability here and it is felt that a practice which increases the number of rate determinations to be made by the Commission should not be invoked unless clearly required as a matter of justice to customers. While it may be feasible in some cases to determine a separate rate for each calendar year or part thereof during which an applicant has sought for relief in a particular rate increase application proceeding, it is not believed this would result in the most equitable rates here.

We have therefore determined upon a test year applicable to each of the four proceedings and have then checked the results of the test year against the apparent results of the utilization of the rates thus determined upon both the applicant and upon its distributor-customers during the remainder of the period for which each such rate would be applicable. In doing this, we have treated the year 1955 as the test year in Docket No. G–5471, the year 1958 actual as the test year in Docket No. G–11982, the year 1959 actual (with any applicable adjustments) as the test year in Docket No. G–17218 and the year ending March 31, 1960 prospective (with prices adjusted to reflect Tennessee's rates in Docket No. G–19983), as the test year in Docket No. G–19984.

Alabama-Tennessee's last rate case prior to Docket No. G–5471 was settled, as appears from the order of March 18, 1954 in Docket Nos. G–2253 and G–2336. This must be assumed to have been a compromise of all interests. Moreover, the theory that one rate case in five years can reasonably be anticipated has been outmoded by inflation and the Phillips case. Accordingly, it cannot be found that any part of expense for earlier rate cases should be included in the rates determined here.

Study of Alternate Source

Alabama-Tennessee seeks authority in these proceedings to capitalize the expenditure of an item of $11,344 spent several years prior to the date of the first proposed rate increase filing which is under consideration here. The item in question represents costs incurred in 1951 or 1952 in connection with proceedings before this Commission, in which Alabama-Tennessee sought to obtain an additional or supplemental gas supply from Texas Eastern Transmission Company (Texas-Eastern).

Since the proposal was not approved by this Commission and Alabama-Tennessee never obtained any natural gas from Texas Eastern as a result of the efforts which resulted in the expenditure of this $11,344, we cannot find any justification for capitalization of the amount involved. It should, however, be clearly understood that the action taken here should not in any way be considered as constituting or reflecting agreement with the Staff's argument at page 25 of its brief that (because the record does not show any immediate inadequacy of Alabama-Tennessee's gas supply), the item in question was not one which could properly be expensed by that company. In fact, this type of costs and charges would appear to be very properly expensed for both tax and regulatory purposes during the year in which they may be incurred.

It is all very well to talk about the duty of the Commission to protect the rate payers from improvident and non-productive corporate excursions. This argument might well apply if the management of Alabama-Tennessee had sought to engage in some business foreign to its normal pipeline operations, such as the development of a coal mine or the operation of a barge line on one of the rivers within its area of operation. The seeking of a second source of the very product (natural gas), the transportation and sale of which constitutes the principal business of Alabama-Tennessee, is well within the scope of

the company's regulated operations and refused to recognize and permit recovery of the costs incurred in an attempt to obtain such alternate or additional supply would constitute an unwarranted assumption of the duties of management by the regulatory agency and an example of the very type of bureaucratic dictation to regulated business, which is one of the principal and strongest arguments of those who are inclined to be critical of all regulation and who seek to return to the early nineteenth century policy of "laissez faire" as to individuals and corporations engaged in business involving the public interest. In the present case, this presents no problem, however, since the expenditure was made at a time well before the presentation for filing of the Docket No. G–5471 application (the oldest application under consideration here) and at a time when management appears to have been well satisfied with the current effective rates and the returns to the stockholders, which were produced by such rates.

Costs of Compression

Alabama-Tennessee argues for special treatment and a departure from this Commission's usual practice in the allocation of the cost of fuel, supplies and maintenance of their compressors. The theory of the Applicant is that its compressors are used only to meet hourly peaks and that this makes them something other than facilities depending upon transmission volumes. We cannot agree with the theory upon which they seek to obtain special treatment for these costs.

It is possible that the recent tendency of the Commission to look more closely than formerly at the end use to which natural gas is intended to be put may make it both desirable and necessary to revise some of the allocation principles, which have been generally followed since the Atlantic Seaboard case[4] was decided in 1952. For instance if limitations are to be placed upon the sales of gas for boiler fuel and similar purposes in the off-peak periods (either by voluntary Commission action or because of a legislative mandate), it would seem appropriate to depart from the equal division of most fixed costs between demand and commodity and to charge a much larger proportion of such costs to the demand category. It does not, however, appear that the time for such departure has arrived or that this is a case requiring such special or changed treatment in the allocation of fixed costs and they have therefore been divided equally between demand and commodity, for the purpose of testing the validity of rates proposed or considered here. The compression costs in question here are charged to commodity.

The Proposed Modification of the Depreciation Rate

Alabama-Tennessee proposes an increase in its depreciation rate from 3.2% to 3.5% per year, effective July 1, 1957, to conform with an estimated 24-year remaining life. To reflect this proposed change in the depreciation rate it has shown, it included increased amounts in its estimated cost of service. The reasons Alabama-Tennessee advances for this increase are that Tennessee has proposed an identical rate of increase in its depreciation rate, effective July 1, 1957, in its filing made in Docket No. G–11980 and that Tennessee is Alabama-Tennessee's sole source of gas.

The Staff contends that the reasons advanced by Alabama-Tennessee for this increase in depreciation rate have no persuasive substance. Alabama-Tennessee relies upon the conclusions first, that Tennessee will be unable to supply gas 24-years hence, and second, that Alabama-Tennessee's plant will be useless in

[4] *In the Matter of Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation*, 11 FPC 43.

consequence. There is no evidence in the record that gas from Tennessee's system will be unavailable to Alabama-Tennessee 24-years hence. Moreover, there is at present another transmission line within practicable reach of Alabama-Tennessee, and competing with Tennessee in Alabama-Tennessee's marketing area. And it appears not only possible but probable that Alabama-Tennessee may have acquired at least one additional source long before the expiration of the twenty-four year period which is claimed to be the remaining life of Tennessee's reserves.

Municipal Association contends that since Tennessee's change in depreciation rate has not been approved by the Commission, Alabama-Tennessee's proposal cannot be approved at this time. The Municipal Association further suggests that the use of the changed depreciation rate will require adjustments to the rate base for past and prospective periods to reflect a modification of the depreciation reserves as well as an income tax adjustment.

It would not make any serious difference to Alabama-Tennessee if the depreciation rate to be allowed is 3.2% or 3.5%, because any increase in the annual depreciation charge will be largely offset in the annual expenses of the company by the corresponding yearly reduction in the rate base of Alabama-Tennessee. Moreover, the evidence presented by AlabamaTennessee on this point was rather inconsistent and entirely dependent upon whether another Hearing Examiner of the Commission in another proceeding affecting Tennessee should see fit to increase the annual depreciation rate of Tennessee from 3.2% to 3.5%, beginning July 1, to conform with an estimated 24-year remaining life.

The question of rate of depreciation is primarly a matter of accounting procedure. The Natural Gas Act does not provide that a change in such procedure requires a hearing. The question of depreciation rate is not really ripe for determination until a similar determination is made in the case of Tennessee. Whether a change of the same nature in the case of Tennessee should be carried forward and made applicable to Alabama-Tennessee is a question which should be considered separately from the present rate case. As suggested by the Staff, it is possible that alternate gas supply sources available to Alabama-Tennessee may make it undesirable to treat the depreciation allowances of that company upon the same basis as that of Tennessee. Parenthetically, it may be noted that Staff Counsel's position in this regard is, to some extent, inconsistent with Staff Counsel's argument to the effect that money spent by Alabama-Tennessee in surveying the desirability of an alternative source of gas should not be allowed as part of the annual expenses of operation of Alabama-Tennessee in the year in which such money was spent. It will be noted, moreover, that the Presiding Examiner's refusal to consider the expense of such alternate-source investigation as a part of Alabama-Tennessee's cost of service is based on the totally different ground that such costs were accumulated at a time when there was no indication that Alabama-Tennessee's rates were too low.

The Proposed Allocation of "Customer Costs"

Alabama-Tennessee has proposed to modify the customary classification of costs, between "demand" and "commodity", by the injection into the classification picture of a third class of costs, designated as "customer costs". These "customer costs" are claimed to include portions of the return, depreciation, taxes and operating expenses, assigned to city gate and main line measuring and regulating stations. Related expenses for customer accounting and collection and sales promotion expense are also included within Alabama-Tennessee's classification of "customer costs".

While it is conceivable that the classification of certain costs as "customer costs" may be right and proper in some cases, the evidence presented in this case does not sustain the burden resting upon the rate-increase applicant of justifying the classification by it of certain costs, as "customer costs". In fact, there is not even a satisfactory showing that the type of costs included as "customer costs" are those to which such a classification could best be applied. Some of such costs are claimed to be assigned on a weighted meter-count basis. The record is not clear however as to whether such weighting was based upon size of meters, frequency of meter-reading or the amount of employee-time required for each reading. In the absence of such showing and of positive and convincing evidence that the variations in cost of metering facilities or the time required for the reading thereof materially affect the overall operating costs of Alabama-Tennessee, the weighted meter method of classifying costs to customers can contribute nothing toward a proper allocation of costs, upon which Alabama-Tennessee's rates can be based.

Other costs assigned by Alabama-Tennessee to the category of "customer costs" included return, depreciation and taxes, as well as certain operating expenses of those facilities described as "distribution plant" by Alabama-Tennessee. It has not been shown that the proportions of such "distribution plant" facilities used to serve any one class of customers was either excessive or inequitably small. In the absence of such a showing, it would appear that the placing of costs, allegedly related primarily to distribution, in a classification other than those of "demand" or "commodity" is unnecessary and could serve no purposeful end, unless it be to (in effect) shift part or all of such costs from the "demand" category to the commodity category, or vice versa.

To the extent that they represent capital costs of facilities, the type of costs described in the preceding paragraph may, in some sense, become sufficiently important to require some special treatment. However, such special treatment would not necessarily be by classification of costs here proposed. If some special rate, applicable to those customers for whose sole benefit certain distribution laterals or special measuring and regulating facilities were required, this could be taken care of, if necessary, by creation of a special "zone". A more satisfactory alternative might be the obtaining of contributions in aid of construction, whose liquidation might be provided for by special contract and with little or no interest payment required in the meantime. The use of such contributions in aid of construction is not uncommon in the case of direct industrial contracts for sale of gas by pipelines. Here, of course, no regulatory problem exists and the procedure serves to keep the cost of facilities, used only for unregulated business, out of the rate base, upon which rates to jurisdictional customers are to be computed.

Another type of costs classified as "customer costs" by Alabama-Tennessee was the allegedly-related expenses for customer accounting and collecting and for sales promotion. The propriety of the assignment of such accounting, collecting and sales-promotion costs, as have been included in this category by Alabama-Tennessee, has not been established by any facts in evidence here. The billing and accounting costs are comparatively small in a company, like the present one, where the total number of customers (utility and direct industrial) is less than a score. Sales promotion costs of the pipeline company are usually (in an area like that of Alabama-Tennessee) accrued in an attempt to acquire interruptible industrial customers for either the pipeline or its utility customers.

Where sales promotion costs are accumulated in a campaign for new residential or commercial customers, they are usually developmental and in an attempt to help the newer or smaller municipal or private utilities. The new and

usually small-at-the-start utility customers of a pipeline company are the ones least able to bear the whole of the costs of a sales campaign. The older and unusually larger utility customers are in much better position to budget a certain proportion of their annual revenues for promotional purposes and such older utility customers frequently put on campaigns for new customers, in which the only assistance sought from the pipeline is the availability of the necessary natural gas to supply the demands (of additional customers or expansion of service to existing customers) generated by the campaign.

Expense wise, the part played by the pipeline in any developmental campaign of a utility customer may well be in inverse ratio to the size of the customer and its ability to pay for such a campaign. To permit the cost of such service to be added to the cost of the class of customers least able to bear such a burden would not constitute sound regulatory policy. Here, however, there appears to be no attempt to charge such costs to any one class of customers and no useful purpose can possibly be served by creation of the proposed classification of "customer costs".

Other cost of service deductions proposed by the intervener

In the testimony of the witness Van Scoyoc and the principal brief filed by the Municipal Association, certain additional items which had been claimed as income tax deductions by Alabama-Tennessee are proposed to be treated in the same manner in the cost of service studies made as to the years 1955 and 1957. The cost of service studies in each year have not been utilized for separate computations of rates for each year or part of a year, when a proposed rate was to be effective under Alabama-Tennessee's various applications, but selected test years have been used in determining the rates for each entire period, when proposed rates to be charged by Alabama-Tennessee to its various customers, were effective under corporate undertaking pending leasing and determination in regard thereto. It is obvious that under what may be described as a "test year method," non-recurring items, while possibly entitled to some overall consideration, if too many in number and all tending in one direction, are not a proper part of the test-year cost of service upon which rates are to be based.

In the 1955 cost of service exhibit of the intervener, it is claimed that a tax deduction in the amount of $3,026 representing the premium part on bonds retired during the year 1955 should also be treated as a deduction from the cost of service accrued by Alabama-Tennessee in that year. This item is a one-year item based on bonds retired during the year 1955 and is non-recurring. For that reason it does not appear that it should be utilized as a reduction in the cost of service, which cost of service should represent the costs incurred by Alabama-Tennessee in a normalized year.

The Municipal Association has raised a similar claim in regard to an item of $8,747 included in the cost of service exhibit presented by said Municipal Association for the period of January 1, 1957, to July 13, 1957, and the period from July 14, 1957, to December 31, 1957. This is a composite cost of service study for the year 1957 which purports to reflect costs, distributed to two periods when different rates are proposed to be effective. If 1957 were to be considered as a test year, the same treatment as in the case of the bond-premium would be given this proposal, which represents the compensation of officers charged to construction work then being carried on and for which tax exemption was claimed. However, this is immaterial here, since 1957 is not being used as a test year period, the rates to be allowed during the locked-in period covered by Docket No. G–5471 being based upon the 1955 test year and those for the period covered by Docket No. G–11982 being tested by the 1958 cost of service.

Another item claimed as a deduction in the 1957 year was an amount of $14,016 for depreciation of rights of way. Insofar as 1957 is concerned this might be disregarded in the same way. However, the same situation occurs in regard to right-of-way depreciation in 1958 which is a test year. Alabama-Tennessee claims this is not to be treated as a credit even though claimed as a tax deduction for the year. There is testimony in the record which makes it clear that the Internal Revenue Service has refused to allow similar items in certain other years and that, because of such action on the part of the Internal Revenue Service, Alabama-Tennessee has agreed to the payment of increased taxes during such years and has filed corrected tax returns in which the right-of-way depreciation is not claimed for other years in which such claims had previously been made, but as to which the tax returns have not yet been audited by the Internal Revenue Service. It is impossible to agree with the argument of the Municipal Association that there is an obligation on the part of a natural gas pipeline company to appeal from a decision of the Internal Revenue Service in a case like this. Not only is the amount involved too small to justify such an appeal, because the cost of appeal may very well exceed the amount saved, but it does not appear that there is any solid ground upon which such an appeal could be successfully prosecuted.

Merit Increases

Alabama-Tennessee claimed that, in the determination of the future rate, consideration should be given to certain increases (described as "merit increases") in wages and salaries of employees. Staff counsel argued that such costs have not been shown to have been incurred in any test year period and that when incurred they will not increase unit costs. In doing this the Staff adopts a conclusion stated by Municipal Association's witness Van Scoyoc, who pointed out that previous salary increases during the period beyond 1955 and 1959 have (on unit bases) been more than offset by increased efficiency of operation.

In fact the studies submitted by the witness Van Scoyoc indicate that the amount of salaries and wages charged to operations in 1955 amounted to $239,046 while in 1959 the total amount charged to operations for such salaries and wages was only $220,398. This indicated that, on a unit of sales basis, the operating labor cost decreased during the period 1954 through 1959 from 2.374¢ per Mcf to 1.70¢ per Mcf of gas. This decline of approximately 67¢ per Mcf amounted to an approximately 28% reduction in the unit cost for labor.

The very use of the term "merit increases" indicates that the purpose of the said increased wages and salaries was to reimburse employees for increased efficiency of operation. Such increased efficiency can be expected to continue in the future and to result (as in the past) in a constantly decreasing unit cost of labor for operations of Alabama-Tennessee. In accordance with the reasoning outlined by the intervener's witness and by staff counsel in their brief, which appears both rational and proper, the claim of Alabama-Tennessee to have such alleged merit increases (to become effective in the future) made a part of the cost of service for the test year, for the rate to be authorized hereafter in Docket No. G–19984, has been disallowed. The total amount involved appears to be $12,267, which should be easily absorbed by the increased volumes expected to be transmitted and sold by Alabama-Tennessee in the future.

Load Factor of Rate Schedule SG–1 Sales

Two of the rate increase proposals of Tennessee, upon which Alabama-Tennessee relies as support and reason for its proposed increases did not call

for any increase in the demand charge of Tennessee. These two rate increases of Tennessee, are the proposed increase in Docket No. G–5259 upon which Alabama-Tennessee relies as the reason for its own proposed increase in Docket No. G–5471, here under consideration, and Tennessee's application in Docket No. G–17166, upon which Alabama-Tennessee relies as the support and reason for its proposed increase in Docket No. G–17218.

In its application in Docket No. G–11982, Alabama-Tennessee recites the fact that under an application filed by Tennessee (Docket No. G–11980) Alabama-Tennessee will experience an increase of 20¢ per Mcf of monthly billing demand and 1.9¢ per Mcf of commodity cost on all gas bought by it from its sole supplier, Tennessee. In order to support the proposed increase of 4.1¢ per Mcf in the price of gas delivered to its smaller public utilities customers under its SG–1 rate schedule Alabama-Tennessee claims to be entitled to bill such customers at a price equivalent to the rates to G–1 customers operating at a 30% load factor. Alabama-Tennessee claims that a 30% load factor is the approximate load factor experienced by its SG–1 customers during the 12 months ended November 30, 1956.

The application for rate increases of Alabama-Tennessee in Docket No. G–19984 is claimed to be based upon increased rates proposed by Tennessee in Docket No. G–19983 filed at practically the same time that Alabama-Tennessee's Docket No. G–19984 application was filed. Tennessee's proposal contained in its Docket No. G–19983 application is for the retention of the commodity charge being collected under bond and an increase of 85¢ per Mcf in the monthly billing demand to be paid by Alabama-Tennessee. In Alabama-Tennessee's proposal for increased rates filed October 5, 1959, it is proposed that customers buying gas under Alabama-Tennessee's rate schedule SG–1 be required to pay an increase of 13.3¢ per Mcf. Alabama-Tennessee claims that this is the equivalent of the increase applicable to its rate schedule G–1 customers at a 21% load factor and states such 21% load factor to be the approximate load factor expected to be experienced by the SG–1 customers during the 12 months ending April 30, 1960.

It appears from the study of past records that the historical load factor calculated for the SG–1 rate schedule of Alabama-Tennessee has been approximately 45%. While this may appear to result in some slight subsidy to the SG–1 customers, it should be kept in mind that the small customer of today may well be the large customer of tomorrow, with any pipeline company. Rates given to such small customers are in most cases developmental rates to enable such customers to build up their load. As the load is built up, the profits of the pipeline tend to increase. If rates to these small customers were to bear their full proportion of the demand costs of the pipeline company in a mathematical manner, it is doubtful whether such small communities would find it economically feasible to put in distribution systems and develop a market for natural gas within their borders. This is true both as to the municipal agencies principally involved here and as to privately owned public utilities or small communities seeking to be served through private public utilities.

It may be noted that Alabama-Tennessee has in the past increased its number of public utility customers by offering to render service to small communities or communities in which the natural gas market would be developed over a period of several years. Such customers appear to have been connected and sought by Alabama-Tennessee on the basis of the approximately 45% load factor developed in the SG–1 rate of Alabama-Tennessee. By order issued September 23, 1955, 14 FPC 986, upon an application filed August 6, 1954, Alabama-Tennessee was authorized to construct additional facilities to serve

Russellville for the first time and to increase service to the Lawrence-Colbert Counties Gas District. This was the result of an application of Alabama-Tennessee and not because of any 7(a) proceeding to require service.

No question seems to have been raised in the past as to the 45% load factor made roughly applicable to the SG–1 rate. There is no reason why customers relying upon such past treatment should now be penalized. This is especially true because of the comparative unimportance of the volumes supplied. In the year 1959, for instance, the total volume of sales to all SG–1 customers of Alabama-Tennessee was 375,445 Mcf out of total jurisdictional sales of 6,997,059 Mcf. The total sales, including nonjurisdictional sales, made by Alabama-Tennessee were 12,959,452 Mcf, in the year 1959.

The total jurisdictional sales of Alabama-Tennessee during the year 1955 were 4,321,800 Mcf of which total 320,779 Mcf were sold to six Rate Schedule SG–1 customers. These six included Athens, Alabama which has since become a G–1 customer and did not include Russellville which was not served with natural gas by Alabama-Tennessee until October, 1957, and whose connection to the Alabama-Tennessee system has been discussed above.

The City of Athens, Alabama was a Rate Schedule SG–1 customer of Alabama-Tennessee until March 1, 1958, according to the service agreement of that company as a Rate Schedule G–1 customer filed with this Commission and made a part of the record in these proceedings by reference. At the present time Hartselle, Alabama which is a Rate Schedule SG–1 customer of Alabama-Tennessee is rapidly approaching the point where it will, of necessity, become a Rate Schedule G–1 customer of Alabama-Tennessee. Incidentally, it may be noted that Russellville (the last Rate Schedule SG–1 customer attached) was stated to be second only to Hartselle in both annual and peak day deliveries during the year ending August 31, 1959, in exhibits to the application in Docket No. G–19984. This is established in the record (as to peak day volumes taken) by Alabama-Tennessee's own report to its stockholders, which is in evidence by reference, having been filed as part of its 1959 report to this Commission.

The 1959 volumes of gas sold by Alabama-Tennessee to its Rate Schedule SG–1 customers amount to only 375,445 Mcf out of a total of 6,997,059 Mcf, as previously stated. It will be observed that in the past several years the proportion of Rate Schedule SG–1 gas to the total jurisdictional sales of Alabama has decreased. It may be noted that Alabama-Tennessee is increasing not only its jurisdictional business but also its nonjurisdictional business wherever possible. In the 1959 annual report to stockholders, which is an item by reference in this proceeding, as previously stated herein, the stockholders are informed of a 10 year contract signed by Alabama-Tennessee with Tennessee River Pulp & Paper Company. This contract is for 6,000 Mcf of natural gas per day on an interruptible basis and requires the Paper Company to take or pay for a minimum of 75% of the contract quantity when available during an operating year of 340 days. Alabama-Tennessee also has interruptible gas sales contracts with Tennessee Valley Authority and with Reynolds Metal Company. Increases in annual volumes of sales to Reynolds Metal Company, Tennessee Valley Authority and Ford Motor Company were attended during 1959 by corresponding increases in peak day requirements. Low load factors of Rate Schedule SG–1 customers (at least to the extent by which they are less than the 45% load factor used in calculating the SG–1 rate) are no hardship to Alabama-Tennessee, which can sell the gas to interruptible industrial or Rate Schedule I–1 customers.

In summary it can be said that in relation to the total sales volumes of Alabama-Tennessee, the Rate Schedule SG–1 sales are only a drop in the

bucket. Apparently, the approximately 45% load factor upon which the said SG–1 rate has been based in the past has been a contributing factor in the successful development of Alabama-Tennessee's markets. No reason can here be seen for departing at this time from the established pattern of the said rate schedule and it is upon this basis that the Rate Schedule SG–1 rates, for the three locked-in periods and for the period beginning April 5, 1960, have been calculated.

The Interruptible Industrial Rate of Alabama-Tennessee

Prior to March 1, 1957, Alabama-Tennessee made no provision for an interruptible industrial rate in its agreements with its distributor customers. On March 1, 1957, Alabama-Tennessee filed its first or original I–1 Rate Schedule, to be effective April 12, 1957, for sale of interruptible industrial gas to its utility customers. The original filed rate was 25.1¢, which was increased to 28.3¢ by the Docket No. G–17218 filing of November 14, 1958, which became effective, subject to possible refund, May 15, 1959. While not legally subject to suspension because it was an industrial rate, Alabama-Tennessee (subsequent to the original filing in Docket No. G–17218) filed a statement with the Commission that it did not desire to collect an increased rate for interruptible industrial gas prior to May 15, 1959, when the increased rates of Tennessee Gas Transmission Company in Docket No. G–17166 became effective under Commission order.

The interruptible industrial rate carries no demand charge but is only a commodity rate. During the portion of the locked-in period of the Docket No. G–5471 proceeding in which this rate was applicable, the I–1 rate of Alabama-Tennessee was 25.1¢ per Mcf. Both Alabama-Tennessee and its utility customers seem to have been reasonably satisfied with the rate. We have not seen fit, as a matter of judgment, to disturb it. The same rate was continued during the locked-in period covered by Docket No. G–11982. In this case the difference between the I-1 rate and the commodity portion of the Rate Schedule G-1 rate of Alabama-Tennessee, as such rate is hereafter fixed in this decision, amounts to only nine-tenths of a cent per Mcf, as opposed to a differential of 3.4¢ per Mcf in the Docket No. G–5471 period. While a difference of only nine-tenths of a cent between the purely commodity interruptible industrial rate does not seem fully adequate, in our judgment, to a completely balanced rate structure, it is not possible for this Commission to increase a rate and the 25.1¢ rate for the Docket No. G–11982 period is not proposed to be altered.

In filing its application for increased rates in Docket No. G–17218, Alabama-Tennessee proposed an increase from 25.1¢ per Mcf to 28.3¢ per Mcf in its I–1 Rate Schedule. For the period covered by this rate and for which refunds in other rates are hereafter ordered, the 28.3¢ rate for interruptible industrial gas is only four-tenths of a cent higher than the rate hereafter found to be the reasonable rate for the commodity element of the Rate Schedule G–1 rate. However, as previously stated, the Natural Gas Act does not authorize increases of filed rates by direction of the Commission. Moreover, there remains a possibility that reductions may hereafter be made in the rates of Tennessee, which is presently the sole supplier of the natural gas sold under various rate schedule by Alabama-Tennessee. In the event that additional refunds may hereafter be required of Alabama-Tennessee because of refunds received by it from its supplier, it will then be possible to so distribute such refunds as to adjust the interruptible industrial rate to the rate applicable to the commodity factor in the Rate Schedule G–1 rate, more equitably.

As a matter of policy and of sound discretion in the adjustment of rates, it is believed that a differential of approximately 2¢ per Mcf constitutes a reasonable minimum difference which should be maintained, in the absence of substantial reasons for other action, between the interruptible industrial or I–1 Rate Schedule of a company such as Alabama-Tennessee and the commodity factor of the G–1 Rate Schedule of such a pipeline company. Failure to maintain such a differential has a tendency to encourage attempts by distributors to seek indiscriminate industrial business, at a time when increasing demands for domestic use of natural gas in new areas and by new customers in old areas, as well as industrial demands of a type which are not competitive with other fuels, because such other fuels do not provide an equally or comparably satisfactory substitute for natural gas, are increasing gas-supply problems.

It is hereafter provided, for the refund periods as to which the rates being collected in Docket No. G–11982 and the rates being collected under Docket No. G–17218 are applicable, that in the event Alabama-Tennessee may hereafter receive refunds from Tennessee under the corresponding Docket Nos. G–11980 and G–17166 of Tennessee, the additional refunds to be made to utility customers by Alabama-Tennessee may be so adjusted that the resulting amount to be retained by Alabama-Tennessee under the I–1 Rate Schedule shall exceed the amount to be retained by Alabama-Tennessee as the commodity factor of its Rate Schedule G–1 by 2¢ or as much thereof as possible. It has not been felt necessary or desirable to make a similar adjustment for the period to July 14, 1957, where the differential between the commodity factor of the Rate Schedule G–1 and the Rate Schedule I–1 rate (strictly commodity) amounts to 3.4¢.

At the other end of the story in the present and prospective rates which have been collected by Alabama-Tennessee under Docket No. G–19984 since April 5, 1960, no adjustment is hereafter authorized in the event of a future refund by Tennessee to Alabama-Tennessee, because it is felt that the cost of making the adjustment and the resulting inconvenience to both Alabama-Tennessee and its customers would not justify an adjustment of two-tenths of a cent. In other words, it is felt that for all practical purposes here the 1.8¢ differential under Docket No. G–19984 between the Rate Schedule I–1 rate of Alabama-Tennessee and the commodity factor of the Rate Schedule G–1 rate of Alabama-Tennessee for the period beginning April 5, 1960 is near enough to the approximate 2¢ minimum differential which appears to be reasonable that no further adjustment should hereafter be required. It may be noted in this connection that the Rate Schedule I–1 as filed in Docket No. G–19984 remains the same as that filed in Docket No. G–17218. Moreover, Docket No. G–19984 sets future rates and circumstances which are only foreseen cannot be estimated with the precision, with which it is possible to determine past facts, as can be done in relation to the locked-in periods here under consideration.

The Temporary Peaking Service Rate

On December 29, 1955, Alabama-Tennessee filed a rate schedule for temporary peaking service to general service customers which it designated as its Rate Schedule TPS–G1. The TPS–G1 rate schedule of Alabama-Tennessee was to be effective only from the date when it was allowed to become effective by this Commission until April 30, 1956. It was to be available to only those general service customers served under Alabama-Tennessee's Rate Schedule G–1, as it then existed, who had met certain requirements as to the increasing of their billing demands under the contracts filed as service agreements under Alabama-Tennessee's general service Rate Schedule G–1, as it existed on April 30, 1955.

This rate schedule permitted the taking of additional gas in excess of the billing demand of the customer under Rate Schedule G–1 of Alabama-Tennessee, but not in excess of the maximum daily demand obligation specified in the buyers' general service gas sales contract. The demand charge under Rate Schedule TPS–G1 was to be $2.25 per month per Mcf of billing demand and 75¢ per Mcf as a commodity charge for all gas delivered.

The record shows that the only communities taking advantage of the TPS–G1 Rate Schedule were Tuscumbia, Sheffield, and Huntsville, all in the State of Alabama. Exhibit No. 4, submitted by Alabama-Tennessee, shows the billing demands units for the four month period and also the annual sales volumes for both G–1 and TPS–G1 sales. The total amount of the TPS–G1 Rate Schedule sales was only 488 Mcf. The billing demands for such sales amounted to 1192 Mcf. As a result, the total revenues for demand and commodity charges was $3,048 out of a total of $2,036,316.34 paid to Alabama-Tennessee by jurisdictional customers during the year 1956. No one bothered to put in any other evidence in the proceeding in regard to the TPS–G1 schedule, although the Staff's exhibit showing proposed rates for the locked-in Docket No. G–5471 period carries a footnote (without explanation) to the effect that no changes are proposed in Alabama-Tennessee's Rate Schedule TPS–G1, which was in effect from December 29, 1955 through April 30, 1956. There is, however, material in the application of Alabama-Tennessee for its subsequent rate increases in Docket No. G–11982, which shows that all of the gas delivered under the TPS–G1 rate schedule was delivered during the month of January, 1956. In addition there is, in Statement G of the Application in Docket No. G–11982, information which shows that the Rate Schedule G–1 billing demands as they existed in January, 1956, were not increased, by reason of the taking of greater amounts of gas, for at least 10 months, by any of the three communities of Tuscumbia, Sheffield and Huntsville.

It is possible to determine that (in the absence of the special peaking service provided by the TPS–G1 rate) each of the said communities would, if they had obtained the same quantities of gas (which they obtained under the TPS–G1 Rate Schedule) under the existing Rate Schedule G–1 rate, have paid at least three times as much for said gas. This resulted from the fact that while the Rate Schedule TPS–G1 commodity rate was almost triple the then effective commodity rate being charged under Alabama-Tennessee's Rate Schedule G–1, the monthly demand charge provided by Rate Schedule TPS–G1 was only five-sixths of the Rate Schedule G–1 demand charge and that the billing demand rate accruing in four months on the Rate Schedule TPS–G1 gas amounted to $9.00 as against $27.00 for a ten-month continuance of the $2.70 billing demand provided for in the Rate Schedule G–1 at that time.

In view of the fact that the intervenor, who represented the three communities in question, did not see fit to put in any substantial evidence in regard to the TPS–G1 rate and did not complain of said rate, it must be assumed that the three communities who bought gas under the rate had no complaint against the said TPS–G1 rate. In view of the analysis heretofore made and the showing that the three communities saved some two-thirds of the cost which they would have had to pay if they had taken the same volumes of gas in January 1956, under Alabama-Tennessee's then existing Rate Schedule G–1, no reason can be seen for allocating any portion of refund moneys for the Docket No. G–5471 period to the TPS–G1 gas.

Federal Income Taxes

In computing Federal income taxes for regulatory purposes herein, the tax allowance for liberalized depreciation permitted by the Internal Revenue

Service has not been so treated as to produce a reduction of the working capital allowance, in the cost-of-service studies made to determine the rates set herein. This procedure follows that of the Commission opinions in El Paso Natural Gas Company, Docket No. G–4769[5] and United Fuel Gas Company, Docket Nos. G–2451 and G–5475.[6] While the El Paso case here referred to was reversed at 281 Fed. 2d., 567, by the Circuit Court of Appeals for the Fifth Circuit, such reversal was on other grounds and did not invalidate the language contained therein in regard to liberalized depreciation. The Commission as a matter of policy has allowed the benefits of such liberalized depreciation to be retained by the pipeline company. In this connection it may be pointed out that liberalized depreciation, under Section 167 of the Internal Revenue Code, only shifts costs from one period to another. It does not relieve the tax payer from the eventual necessity of paying such costs. The determination by a tax payer as to whether to take advantage of such liberalized depreciation is a matter of sound business discretion and should be considered in relation to its effect upon the financial structure of the tax payer, rather than upon any consideration of its effect upon third parties or the benefits which they might receive therefrom.

From the standpoint of customers of Alabama-Tennessee, the allowing of that company to retain the benefits of the liberalized depreciation which it is permitted to take under Section 167 of the Internal Revenue Code raises only one question and that is whether certain costs should be paid now by present rate payers or passed on to further rate payers when it becomes necessary for Alabama-Tennessee to meet the postponed liability incurred by it under the Federal Tax statutes. It appears equitable that these costs should be paid by the present rate payers rather than by some future generation of rate payers, at a time when gas rates will probably be much higher than they are now. It is therefore found that the retention by Alabama-Tennessee of the temporary benefits due to accelerated depreciation, as provided for in the Internal Revenue Code, is in the overall public interest and should be permitted in these rate determinations.

No problem of statutory depletion or the expensing of intangible drilling costs, which may be allowed as a tax credit, is present in the present proceedings. Alabama-Tennessee does not produce any gas but purchases its entire supply. Neither is there any problem here of consolidated returns in which the tax losses of one affiliated corporation (whether regulated or not) may be used as an offset to taxes accruing to or for the regulated company whose rates are being determined. To the extent that it is necessary in these proceedings to consider modifications of the income tax structure of a minor nature, these modifications have been heretofore discussed in earlier portions of this decision and it is not necessary to again refer to them at this point.

Counsel for Alabama-Tennessee proposes that, in determining peak day demands in these proceedings, such determination be made upon the averaging of the 3-day peak period of the winter season which includes the beginning of each calendar year and the 3-day peak period occurring during the winter season which includes the end of the said calendar year. In their reply brief, they argued for the use of the average of the said two peak day periods upon the basis of their interpretation of Commission action in a case involving East Tennessee Natural Gas Company, Docket No. G–5470.[7]

[5] 22 FPC 260 at 265–267.
[6] 23 FPC 127 at 130–131.
[7] Commission order of February 17, 1961 in Docket No. G–5470 [25 FPC 295]

In these consolidated proceedings it has already been determined that neither the fixing of separate rates for separate portions of the period, during which the rates are to be determined in each of the four consolidated proceedings, nor the determination of such rates upon the basis of a consolidation of costs throughout the entire period in which a particular proposed rate was collected subject to possible refund, is desirable. It has been determined that rates for each of the three past periods, covered in Docket Nos. G–5471, G–11982 and G–17218, as well as the present and future rates involved in Docket No. G–19984, should be fixed upon the basis of an appropriate test year and such test years have been heretofore stated in this decision.

Consideration has been given to Alabama-Tennessee's suggestion of the use of the average of two 3-day peak periods. Upon such consideration it has been determined that use of such a combination of two 3-day peak periods would be undesirable in any of the four proceedings under consideration here.

A study of Alabama-Tennessee's own exhibit, showing cost of service data for the 12-months ended December 31, 1955, discloses that on December 31, 1954 the net gas plant actually in service amounted to $4,521,237.74. The total net gas plant in service, according to the same exhibit, on December 31, 1955 amounted to $4,503,408.19. The difference between the two figures amounts to approximately four-tenths of one percent. The 3-day peaks, which Alabama-Tennessee claims should be used for 1955, were 25,119 Mcf on February 10, 11 and 12, 1955 and 26,911 Mcf on November 28, 29 and 30, 1955. Both peaks occurred during the year 1955 and it appears clearly preferable to use the November peak, which is also the highest single peak, rather than the average of the two 3-day peaks. It may be noted, incidentally that the relationship of the jurisdictional and nonjurisdictional gas in the February and November peaks is approximately proportional.[8] There thus appears to be no sound reason for using an average of two 3-day peak days period in allocating demand charge for the 1955 test year, adopted for determination of the Docket No. G–5471 rates.

For the 1958 test year used in Docket No. G–11982, Alabama-Tennessee's cost of service exhibit shows net gas plant in service on December 31, 1957 of $5,804,811.59 and the corresponding figure for December 31, 1958 is $6,224,856.01. While a comparison of these two figures would show a variance of some 7 percent between the gas plant in service at the beginning and the end of the year, such a comparison would be misleading if used to justify the use of the average of two peak days periods as a basis for the allocation of the demand component of the cost of service.

Further study shows that gas plant in service remained fairly constant from December 31, 1957 through November 30, 1958 and was actually $37,000 lower on November 30, 1958 than on December 31, 1957. This would indicate that rather important facilities were completed and made available for service in December 1958. Turning to the two peak day periods suggested by Alabama-Tennessee, it appears that the first of said periods occurs on 15, 16 and 17 February 1958 and the second such peak period did not occur until January 4, 5 and 6, 1959, a date outside the test year period.

Since the smaller capacity was apparently available during eleven of the twelve months in question here, it would be misleading to use a peak period occurring in January 1959. As a matter of fact, the computation used in determining the rates to be applicable in Docket No. G–11982 (based upon the test year 1958) shows that the portion of the demand which is jurisdic-

[8] The nonjurisdictional peak of February 10, 11, and 12, 1955 amounted to 15,164 Mcf and the nonjurisdictional peak of November 28, 29, and 30, 1955 amounted to 16,236 Mcf.

tional amounts to 76.4917% as opposed to a figure of 74.91% arrived at by Alabama-Tennessee on the basis of the average of the two peak periods proposed by it. It is believed that the computation arrived at on the basis of the single peak period, February 15, 16 and 17, 1958, is more equitable than that proposed by the rate increase applicant.

For the year 1959, which has been used for the test year in Docket No. G–19984, Alabama-Tennessee shows actual net gas plant in service of $6,224,856.01 on December 31, 1958 and $6,469,269.12 on December 31, 1959. The difference here amounts to something less than 4%, but again there is an increase of more than $360,000 between November 30, 1959 and December 31, 1959 which apparently results from completion of facilities. The 1958-59 peak period used by Alabama-Tennessee occurs on January 4, 5 and 6, 1959.

The end-of-year 3-day peak period, did not occur until March 2, 3 and 4, 1960, approximately one month before the end of the period for which the rates determined upon in Docket No. G–17218 are to be applicable. It would appear that this fact alone would be sufficient to justify refusal to consider the double peak day proposed by Alabama-Tennessee. In this case, it may be noted that the overall percentage of jurisdictional to total demand used herein is 75.3789% as against 75.94% under the formula proposed by Alabama-Tennessee.

For the future rate to be determined in Docket No. G–19984, the 3-day peak period of March 2, 3 and 4, 1960 has been utilized to allocate demand between jurisdictional and nonjurisdictional. This rate is the rate which the utility customers (as well as Alabama-Tennessee) must live with for a future period, which it may be hoped will not be too short. The percentage of gas allocated to jurisdictional businesses upon the basis of this 3-day peak is 76.4584. It is believed that the use of a single peak day period for future rates is desirable. In fact the use of any other peak day period would be in no way related to the presently anticipated future volumes, would go beyond any period for which evidence has been presented in the present proceedings, and would be purely speculative.

Alabama-Tennessee's claim of support by the Commission's order of February 17, 1961, in the case of East Tennessee Natural Gas Company, Docket No. G–5470 for its proposed use of two 3-day peak periods has been heretofore noted. It should be noted also that, in that proceeding, the problem of determining a proper peak period for distributing demand costs was complicated by excess pipeline capacity,[9] which was available for storage of gas, and by the ability of East Tennessee to make an arrangement with its largest nonjurisdictional customer for reduction of peak day deliveries of firm gas, which permitted serving of interruptible gas requirements of both direct and resale customers of East Tennessee upon the peak demand period of the 1956-57 winter season. The available storage capacity had apparently permitted full delivery of both firm and interruptible demands in years prior to 1957. There is certainly no evidence here of storage capacity, such as may have been a factor in the East Tennessee case and there is no suggestion here of a backing-off of deliveries by any firm gas customer, either jurisdictional or nonjurisdictional, to permit deliveries of interruptible gas on peak days by Alabama-Tennessee. Moreover, substantial variations, from year to year, in the relative peak demand use of gas by jurisdictional and nonjurisdictional customers, referred to in the Docket No. G–5470 order of the Commission, are not present here.

[9] It is stated in the order of February 17, 1961 that; "There is some evidence in the record that a large portion of the pipeline was constructed of 22-inch pipe although a 16-inch pipe would have satisfied delivery requirements."

In fact, the variation in allocation to jurisdictional and nonjurisdictional sales peak periods demands (both applicable to Docket No. G–5471 rates) is less than one percent, being 62.37% jurisdictional in 1955 and 63.34% jurisdictional in 1956. The combination of the 1955 peak period referred to above and the January 1957 peak, applicable to the part of 1957 covered by the G–5471 proceeding, would result in the allocation of 66.72% to jurisdictional peak demand. The 1955 peak period has been used for allocation of demand here.

The peak day periods used in determining allocations of demand costs in Docket Nos. G–11982, G–17218 and G–19984, while varying substantially from the relative levels of jurisdictional and nonjurisdictional peak demands utilized in determining Docket No. G–5471 rates, are very close to each other. This is apparent, when the 76.4917% of jurisdictional peak demand for the 1958 peak period (used in Docket No. G–11982) is compared with the 75.3789% of jurisdictional peak demand in the 1959 peak period (used in Docket No. G–17218) and 76.46% in 1960 (used in Docket No. G–19984).

Rates and Refunds in Docket No. G–5471

The period covered by suspension in Docket No. G–5471 extends from December 15, 1954 through July 13, 1957. Natural gas was delivered by Alabama-Tennessee to jurisdictional customers under Alabama-Tennessee's G–1 and SG–1 Rate Schedules through the whole of such period. Gas was also delivered to jurisdictional customers under the Alabama-Tennessee TPS–G–1 Rate Schedule which became effective as of December 29, 1955 and continued in effect until April 30, 1956, as well as under Alabama-Tennessee's I–1 Rate Schedule (interruptible industrial gas) from April 12, 1957 through July 13, 1957.

As previously stated the reasonableness of the rates charged by Alabama-Tennessee to jurisdictional customers during the period when the Docket No. G–5471 rates were in effect have been determined upon the basis of the cost of service showing for the calendar year 1955. If it had been possible to dispose of the Docket No. G–5471 proceeding expeditiously after the rates became effective subject to refund, the G–1 and SG–1 rates would, (under normal conditions) have been tested on the basis either of a 1955 test year, or of a 1954 test year, adjusted as to volumes and cost, to show the changes in these two categories which had occurred or were expected to occur during the year 1955. The TPS G–1 Rate Schedule of Alabama-Tennessee which were effective from December 29, 1955 to April 30, 1956 (although no gas had been delivered under this said schedule prior to January 31, 1956 at the very earliest), and the I–1 Rate Schedule which did not become effective until April 12, 1957, obviously did not result in any deliveries during the year 1955. For reasons which will hereafter be stated, this fact is immaterial to our determination of proper rates for the period between December 15, 1954 and July 13, 1957, when Docket No. G–5471 rates were in effect.

Modifications of the cost of service studies presented in evidence, which modifications have heretofore been discussed and explained, result in showing the jurisdictional cost of service of Alabama-Tennessee in 1955 to be approximately $1,773,735 of which some $835,924 is chargeable to demand and $937,811 to commodity. In order to assign a proper portion of the demand to the Rate Schedule SG–1 customers a computation has been made upon the basis of 1955 for said rate schedule SG–1.

As a result of the computation made on the basis of the 1955 test year it has been determined that the demand charge of $2.70 per Mcf to the Rate Schedule G–1 customers is not unreasonable or discriminatory. It may be noted that the Docket No. G–5471 filing did not increase the monthly demand charge

for Rate Schedule No. G–1 customers. Previous to December 15, 1954, there appears to have been a noticeable although not large tilt in favor of commodity as against demand. The Docket No. G–5471 rate, as filed, did not entirely eliminate this tilt although it did eliminate the greater portion thereof. Since no increase in the demand rate is involved in the Docket No. G–5471, filing, and the previous tilt is considerably reduced thereby, it does not appear desirable to reduce this rate below that previously in effect as the result of a settlement approved by this Commission March 11, 1954, even if such reduction were possible in a Section 4(e) proceeding.

The computations which have been made, on the basis of the 1955 test year, show that the commodity rate of 23.15¢ proposed by Alabama-Tennessee in its Docket No. G–5471 rate increase application is unreasonable and excessive. These computations indicate that a commodity rate of 21.7¢ per Mcf for sale of gas to jurisdictional customers of Alabama-Tennessee's Rate Schedule G–1 constitutes a reasonable and proper charge and allows adequate compensation to Alabama-Tennessee for the service rendered by it.

Upon the basis of the 45% load factor for Rate Schedule SG–1 rates of Alabama-Tennessee that has heretofore been determined, more than $63,000 of the total demand charge paid by Alabama-Tennessee should be assigned to the Rate Schedule SG–1 deliveries made by Alabama-Tennessee during that year. The resultant figure obtained by the addition of such portions of demand charge to the commodity charge for 3,723,779 Mcf of natural gas delivered to said Rate Schedule SG–1 customers, would result in rates to such customers of 41.5¢ per Mcf of all gas purchased by them from Alabama-Tennessee.

Upon the basis of the modification which it has been necessary and desirable to make to the cost of service studies presented in these consolidated proceedings for the year 1955, and the computations made thereon, it has been determined that Alabama-Tennessee's proposed Rate Schedule SG–1 rate of 42.65¢ per Mcf for the period December 15, 1954 through July 13, 1957 is excessive and unreasonable. It further appears that a rate of 41.5¢ per Mcf for all gas sold under the SG–1 Rate Schedule of Alabama-Tennessee during the period, when the Docket No. G–5471 rates were in effect subject to refund, is reasonable and is compensatory to Alabama-Tennessee.

During that portion of period covered by the Docket No. G–5471 rates, which extended from December 29, 1955 through April 30, 1960, the temporary service rate, designated as Alabama-Tennessee's TPS–G1 Rate Schedule was available to Alabama-Tennessee's jurisdictional customers, who were purchasing gas under Alabama-Tennessee's GS–1 Rate Schedule. Only three of the said customers availed themselves of the TPS–G1 service. The said TPS–G1 rate was in effect for approximately four months and has heretofore been discussed. It does not appear that rates charged to the three customers who purchased gas under the TPS G–1 Rate Schedule were in any way unreasonable. On the other hand the rates do not appear to have been unfair to other customers. The total gas purchased under the said Rate Schedules TPS–G1 amounted to 488 Mcf, which is less than one ten-thousandth, or one one-hundredth of one percent, of all the gas sold to jurisdictional customers by Alabama-Tennessee during the calendar year 1956. It has heretofore been determined that the said TPS–G1 Rate Schedules of Alabama-Tennessee, in effect from December 29, 1955 through April 30, 1956 is not unreasonable or discrimatory.

On March 1, 1947, for the first time, Alabama-Tennessee filed an interruptible industrial rate schedule designated as its FPC Rate Schedule I–1. In accordance with a request of Alabama-Tennessee, temporary authority was granted (in Docket No. G–12263) to make a sale under said I–1 Rate Schedule to Muscle Shoals Natural Gas Corporation (Muscle Shoals), one of the existing Rate Schedule G–1 customers of Alabama-Tennessee. In a letter notifying

Alabama-Tennessee of the temporary authorization for the sale to Muscle Shoals it was provided that Rate Schedule I–1, tendered on April 1, 1957, should be subject to refund in Docket No. G–11982. In view of the fact that industrial rate schedules are not subject to suspension, and the language in the letter of temporary authorization, issued by the Secretary of this Commission relating the said I–1 Rate Schedule to Docket No. G–11982 rates, which had been filed on January 14, 1957, approximately one and one-half months prior to the tendering of the I–1 Rate Schedule and which were (at the time of the temporary authorization) in suspension to July 14, 1957, the I–1 Rate Schedule (as filed March 1, 1957) will be fully discussed in connection with Docket No. G–11982 rates The fact that such rate schedule exceeds by 3.4¢ per Mcf the commodity rates found unreasonable for Rate Schedule G–1 customers during Docket No. G–5471 period is therefore immaterial here.

The rate schedules for both demand and commodity, applicable to the Docket No. G–5471 period on the basis of the test year, have been checked against the 12-month period ending December 31, 1956 and the 6-month period ending June 30, 1957, to determine whether the said rates are equitable to both the customers and the company.

When related to the volumes of natural gas delivered during the periods in question, the excess amounts of such rates, which were collected subject to refund for the 1956 and 1957 periods to which the G–5471 rates were applicable (except that portion of the latter period from July 1 through 13, 1957) is within a tenth of one percent in each case of the excess shown for the test year.

The excess shown for 1956 is $70,183, as related to a total volume of 4,913,698 Mcf, and the excess shown for the first six months of 1957 is $40,138, as related to a total volume of 2,817,462 Mcf, as compared to $60,367, related to a total volume of 4,321,800 Mcf in the 1955 test year. Volumes delivered under the TPS–G1 Rate Schedule in 1956 and under the I–1 Rate Schedule in the 1957 half-year period are not included in the volumes used in this calculation.

Volumes and revenues for the period from December 15, 1954 through December 31, 1954 are not available in any of the exhibits placed in evidence. For the period July 1, 1957 to July 13, 1957 it is possible to compute the jurisdictional volumes by using Exhibit No. 21 presented by Alabama-Tennessee. The said exhibit No. 21 does not contain any breakdown of sales between the G–1 and SG–1 Rate Schedules of Alabama-Tennessee. For all practical purposes it is impossible to determine what excess has been collected by Alabama-Tennessee during the two short periods in December 1954 and July 1957 discussed above.

We are hereafter provided for refund in Docket No. G–5471 based upon the G–1 commodity rate of 21.7¢ and the SG–1 rate of 41.5¢. This results in a refund of 1.45¢ per Mcf to Rate Schedule G–1 customers and a refund of 1.15¢ per Mcf to Rate Schedule SG–1 customers. In computing the amounts to be refunded to each class of customers, it will be necessary for Alabama-Tennessee to determine the additional refunds due for the periods in December 1954 and July 1957 for which figures were not available in the record.

Rates and Refunds in Docket No. G–11982

For the locked-in period beginning July 14, 1957 and ending May 14, 1959, during which the rates filed by Alabama-Tennessee in Docket No. G–11982 were being collected subject to refund, the said rates as proposed by Alabama-Tennessee were a Rate Schedule G–1 rate having a demand element of $2.90 per month and a commodity element of 25.05 cents for Mcf, an SG–1 Rate

Schedule of 46.75 cents per Mcf and an I–1 Rate Schedule of 25.1 cents per Mcf. As previously stated these rates have been tested against cost-of-service studies for the calendar year 1958, adjusted in conformity with the various changes in such cost studies which have been heretofore stated to be necessary, and which have been discussed herein.

Computations, made upon the basis of the cost of service for 1958, show that the demand charge of $2.90 per month proposed by Alabama-Tennessee would result in an indicated excess of actual revenues over cost of service and would be unreasonable. As previously stated, Alabama-Tennessee and all of its jurisdictional customers, except the City of Corinth, arrived at a settlement agreement on the basis of a $2.70 demand charge in Docket No. G–11982. A study of the actual revenues collected by Alabama-Tennessee during the calendar year 1958, and of the cost of service related to demand and commodity, shows that the $2.70 rate (if also applied on the 45% load factor basis to the SG–1 Rate Schedule) would shortchange demand in favor of commodity by more than $40,000 during the year. Alabama-Tennessee had indicated, however, its willingness to accept the $2.70 rate, by filing such rate as its demand rate in its next rate increase application in Docket No. G–17218, at a time when its total costs had been increased. Any deficiency of course would be chargeable to commodity, if Alabama-Tennessee is to recoup its cost of service. It does not appear that the charging of the deficiency involved here to commodity would be unfair or inequitable to the customers of Alabama-Tennessee. As a result of the computations necessary to create rates which will compensate Alabama-Tennessee adequately and at the same time provide reasonable rates to Alabama-Tennessee's utility customers, it has been determined that a commodity rate of 24.2¢ for the Rate Schedule GS–1 customers of Alabama-Tennessee is reasonable and appropriate. It has also been determined that a rate of 43.9¢ per Mcf for Rate Schedule SG–1 customers, during the period from July 14, 1957 through May 14, 1959, is reasonable and appropriate.

From the finding that the lower rates discussed above are reasonable, it necessarily follows that the demand rate of $2.90 originally sought by Alabama-Tennessee for Rate Schedule G–1 customers in Docket No. G–11982, as well as the commodity rate of 25.05 cents proposed for such customers in the rate-increase application in Docket No. G–11982 are found not to be reasonable. This also applies to the rate of 46.75 cents per Mcf sought in this rate-increase application for the sale of gas by Alabama-Tennessee to its SG–1 customers.

The Rate Schedule I–1 rate of 25.1 cents per Mcf, which was made effective April 12, 1957 (some three months prior to the date when the other G–11982 rates became effective subject to refund) appear to be a reasonable rate, if the rates of Tennessee in its Docket No. G–11980 are not hereafter reduced. Since the differential between the commodity charge to Alabama-Tennessee's Rate Schedule G–1 customers is only nine-tenths of a cent less than the charge to the Rate Schedule I–1 customers, it would appear desirable, if the rates paid by Alabama-Tennessee to Tennessee are hereafter substantially reduced, to make some adjustment in the differential between the Rate Schedule I–1 rate and the commodity factor of the Rate Schedule G–1 rate. In order that the Commission may hereafter have the unquestioned right to make some adjustment of the said differential it is hereinafter provided (in the event that refunds are made by Tennessee to Alabama-Tennessee under Tennessee's Docket No. G–11980) that the right is reserved to the Commission to so adjust any refunds that Alabama-Tennessee may be directed to make to its customers, because of refunds made by Tennessee in Docket No. G–11980, that such differential may be increased to not more than 2-cents per Mcf.

In order to test the reasonableness of the rates developed in Docket No. G–11982 by the use of the test year 1958, the volumes delivered to G–1 and SG–1 customers during the period from July 14, 1957 through December 31, 1957 and the period from January 1, 1959 through May 14, 1959 have been checked against the indicated excess revenues for the said 1957 and 1958 periods. In the case of the 1958 period such a check shows that the variance, as between the 1957 and 1958 segments of the locked-in period covered by Docket No. G–11982 rates, amounting to less than one-tenth of one cent per Mcf. In the case of the 1959 segment of the said locked-in period, it appears that there is an actual variance of approximately two-tenths of a cent per Mcf between the 1958 and 1959 segments of the overall locked-in period.

It may be noted here that in the case of the I–1 rate, which has not been found to be unreasonable, the rate has, as previously stated, been declared to be in effect as part of the Docket No. G–11982 rates, from the time of its original filing even though it thus became effective some three months prior to the effective date when the G–1 and SG–1 rates, proposed in Docket No. G–11982, began to be collected subject to refund. These is a slight element of balancing in the fact that approximately three months of the supply of gas utilized for the said Rate Schedule I–1 sales were paid for at Tennessee's rates as they existed prior to July 14, 1957. Howover, the volumes sold under this rate schedule prior to July 14, 1957 amount to only 24,008 Mcf as against 386,586 Mcf sold under the I–1 Rate Schedule between July 14, 1957 and May 14, 1959.

The reduction in the G–1 and SG–1 rates for the Docket No. G–11982 locked-in period makes it necessary to direct the refunding by Alabama-Tennessee to its utility customers of any sums collected from said customers in excess of the rates herein determined to be just and reasonable. Such excess amounts to 20 cents per Mcf of billing demand and .85 of a cent per Mcf of commodity in the case of the G–1 rate, and 2.85 cents per Mcf delivered by Alabama-Tennessee to its Rate Schedule SG–1 customers during the said locked-in period. No refund is presently required in the case of Rate Schedule I–1 gas sold by Alabama-Tennessee in the period covered by Docket No. G–11982 rates. The possibility of further refunds remains, in the event that Tennessee makes refunds to Alabama-Tennessee in Docket No. G–11980.

Rates and Refunds in Docket No. G–17218

As previously stated, the test year 1959 was used for the determinations of rates to be charged by Alabama-Tennessee during the locked-in period covered by Docket No. G–17218. In order to properly and equitably determine the required revenues for the test year 1959 applicable to the said Docket No. G–17218 rates, it was necessary to adjust the cost of purchased gas for the portion of the year 1959 ending on May 14, of that year to reflect the theoretical impact of the increased prices charged by Tennessee for such gas after May 15, under Tennessee's Docket No. G–17166 if such increased prices had been in effect throughout the whole year. As adjusted to reflect the impact of the increased rates of Tennessee paid by Alabama-Tennessee in the period prior to May 15, 1959, the said cost of service amounts to approximately $3,443,972 as against actual revenues collected during the said test year of $3,427,938. The fact that the actual revenues are less than the cost of service is due, however, to the fact that the actual revenues for the period of approximately 4½ months before the Docket No. G–17218 rates became effective subject to refund were paid upon the basis of the earlier rates being collected subject to refund in Docket No. G–11982. Computations based upon the deliveries of Rate Schedule G–1 gas and the billing demand for such gas show that a considerable excess

would have been collected if both the Docket No. G–17218 rates of Alabama-Tennessee and the Docket No. G–17166 rates of Tennessee had been effective throughout the entire 1959 test year.

Computations made upon the basis of an adjustment for the period between January 1 and May 14, 1959 have resulted in the development of a rate of 27.9¢ per Mcf as the proper commodity charge for gas delivered to Alabama-Tennessee's utility customers under its Rate Schedule G–1. The $2.70 per month demand charge is in fact a decrease rather than as increase from the rates previously being collected by Alabama-Tennessee subject to refund, under its Docket No. G–11982 rate schedules. While this rate appears to result in collection of demand charges in excess of those actually shown by the annual cost of service figures for 1959 (as adjusted), there is nothing that can be done at this time to reduce the said $2.70 per month demand charge. The figures developed, however, for the test year in regard to commodity indicate that the commodity charges proposed by Alabama-Tennessee for its sales to Rate Schedule G–1 customers and Rate Schedule SG–1 customers in the Docket No. G–17218 filings are unreasonable and should be reduced.

Comparison of the actual revenues with the delivery volumes for the various classes of sales made by Alabama-Tennessee under its several rate schedules indicate that a reasonable charge for the commodity element of the gas sold under the Rate Schedule G–1 of Alabama-Tennessee, during this period, is 27.9¢ per Mcf. Computations made on the basis of an assumed 45% load factor for Alabama-Tennessee's Rate Schedule SG–1 customers indicate that 47.6¢ per Mcf constitutes a reasonable rate for such sales. Since the rate proposed by Alabama-Tennessee in Docket No. G–17218 for sales to Rate Schedule I–1 customers of 28.3¢ per Mcf is only four-tenths of a cent per Mcf higher than the commodity portion of the corresponding G–1 rate, it appears that the said Rate Schedule I–1 rate of 28.3¢ is not unreasonably high. This Commission is not authorized to increase rates in a Section 4(e) hearing. It must be found that, under the present circumstances and in the absence of any reduction in the commodity rate of Tennessee in its Docket No. G–17166, the said 28.3¢ rate of Alabama-Tennessee for gas sold under its Rate Schedule I–1 rate during the locked-in period covered by Docket No. G–17218 is a reasonable rate.

On the basis of the rates arrived at by the computations discussed herein, it appears that Alabama-Tennessee should refund to Rate Schedule G–1 customers eight-tenths of one cent per Mcf for all gas delivered under its G–1 Rate Schedule during the period from May 15, 1959 through April 4, 1960. Alabama-Tennessee should also refund 1.1 cent per Mcf to its Rate Schedule SG–1 customers for all gas sold and delivered to such customers during the same period. For reasons heretofore stated no refunds are due upon the basis of the demand component of the Docket No. G–17218 rates of Alabama-Tennessee nor upon the Rate Schedule I–1 rates of Alabama-Tennessee for the same period. In the event that refunds may hereafter be ordered paid by Tennessee to Alabama-Tennessee under Tennessee's Docket No. G–17166, it is possible that the resultant additional refunds made by Alabama-Tennessee to its customers may be adjusted to provide a differential, not exceeding 2¢ per Mcf of the Rate Schedule I–1 rate of Alabama-Tennessee over the commodity component of the Rate Schedule G–1 rate and the portions of the SG–1 rate of Alabama-Tennessee represented by the inclusion of a demand element of a load factor basis.

Comparison of the adjusted test year 1959 figures with the volumes and revenues actually received during the period between May 15, 1959 and March 31, 1960 do not show any variations from the test year which would

materially affect the interests of either Alabama-Tennessee or its utility customers. No figures are available in the record for the period from April 1 to April 4, 1960 and it is assumed therefore that such figures would not materially alter the situation. In any event the effect of any changes during such a four-day period would be minimal.

Refunds and Future Rates in Docket No. G–19984

In the case of the rate increase application proceeding in Docket No. G–19984, rates must be determined for a period beginning April 5, 1960, and extending through a future period, the length of which has not yet been determined. In doing this, it will be necessary to determine the basis upon which refunds (if any are required) should be made by Alabama-Tennessee to various classes of jurisdictional customers of excess charges for gas previously paid for by the said customers. In addition the machinery must be put in motion for the filing, if necessary, of such new rates as may be found to be reasonable for the future sale of natural gas by Alabama-Tennessee to its its jurisdictional customers.

For this purpose, Exhibit No. 45 (presented in evidence by the intervener-Municipal Association) has been utilized as the basic source of volumes, revenues and cost of service information. Necessary adjustments have been made to correctly reflect the determinations herintofore made in regard to regulatory costs and various other matters. The accuracy of figures used in the intervener's exhibit have also been checked against other exhibits and other documents which may be part of the record and which form a part of the general knowledge and expertize available to the presiding officer and to the Commission. The future demands of Alabama-Tennessee's utility customers as well as the comparative future demands of its direct industrial customers are not known and must be necessarily estimated. This is also true as to the continuance of future variations in the level of various items entering into the cost of service by Alabama-Tennessee. For this reason the element of judgment on the part of the presiding officer and of the Commission, in the fixing of the future rates which are a part of the Docket No. G–19984 determination is more important than in the case of the other three proceedings, where the costs (with the possible exception of future refunds from Tennessee) may be determined with a degree of definiteness impossible in estimates made for the future.

Exhibit No. 45 shows that during the year ending March 31, 1960, which is the latest available period of 12 months for which figures appear in the record, Alabama-Tennessee sold to its various jurisdictional customers 7,706,375 Mcf of natural gas. Of this amount 6,979,604 Mcf were sold to Rate Schedule G–1 customers, 449,067 Mcf were sold to SG–1 customers and 277,704 Mcf were sold and delivered to Rate Schedule I–1 customers. The billing demands of the Rate Schedule G–1 customers during this period appear to have amounted to 531,654 Mcf. A billing demand of 32,809 Mcf has been allocated to the SG–1 customers under the 45% load factor formula used in determining the rates applicable to the sales to such customers.

It has been determined by computation that, upon the basis of the sales during the year ending March 31, 1960, the commodity rate applicable to Rate Schedule G–1 sales and the rates at which gas is proposed to be sold to SG–1 customers by Alabama-Tennessee in its Docket No. G–19984 rate increase application are not reasonable. It has been further determined by computation that 26.5¢ per Mcf is a reasonable rate for the commodity element in the sale to Alabama-Tennessee's Rate Schedule G–1 customers and that 51.9¢ per Mcf is a reasonable rate for the sale of natural gas to Alabama-Tennessee's

SG–1 customers. Since the I–1 rate of 28.3¢ per Mcf is 1.8¢ per Mcf higher than the commodity portion of the Rate Schedule G–1 rate of Alabama-Tennessee as computed, such proposed I–1 rate (which incidentally does not constitute an increase over the previously collected Docket No. G–17218 rate for such sales) appears to presently constitute a reasonable rate.

The increased costs of gas from Tennessee to Alabama-Tennessee which are the basis of the proposed increases of Alabama-Tennessee in Docket No. G–19984 consists solely of an increase of 85¢ per month in the billing demand charge. It has been determined by computation based upon the figures for the year ending March 31, 1960, that a reasonable rate for the demand factor of the Rate Schedule G–1 rate is $3.48. This is 7¢ per month less than the increased proposed and being collected subject to refund by Tennessee from Alabama in Docket No. G–19983. It has been possible because of the increased demand charges to reduce the commodity charge under the Rate Schedule G–1 rate in the Docket No. G–19984 period 1.4¢ per Mcf below the rate which has been found to be the reasonable rate for the commodity factor of the Rate Schedule G–1 rate in Docket No. G–17218.

The 45% load factor for Rate Schedule GS–1 customers has been retained, because this seems to be an equitable load factor for this group of customers and to have, in the past, induced the growth of the demands of such customers, with an orderly relation between peak and average demands. This appears to have operated to the advantage of both Alabama-Tennessee and its utility customers.

It is entirely possible that, if it is hereafter determined in Docket No. G–19983 that the rates charged by Tennessee to Alabama-Tennessee should be reduced for the future and that refunds should be made by Tennessee to Alabama-Tennessee for some portion of the rates now being collected subject to refund by Tennessee in Docket No. G–19983, the Rate Schedule G–1 rate of Alabama-Tennessee (as hereinbefore determined) may cease to be a reasonable rate. Such unreasonableness, if hereafter found to exist because of a reduction in the rates charged by Tennessee to Alabama-Tennessee, will necessarily also affect the reasonableness of the Rate Schedule SG–1 rate of Alabama-Tennessee, because the said SG–1 rate includes a demand element computed on the basis of a 45% load factor. If any reductions are hereafter required from Tennessee under the Docket No. G–19983 rates of that company or the prior rates charged to Alabama-Tennessee under rate schedules filed in Tennessee's Dockets No. G–5259, G–11980, G–17166 it is possible that the rates being charged for commodity to Alabama-Tennessee's Rate Schedule G–1 customers and the rates charged to Rate Schedule I–1 customers may thereafter become unreasonable and reductions in such rates may also hereafter be required by this Commission.

For the present, and in the absence of any reduction in the rates charged by Tennessee to Alabama-Tennessee, it has been determined that Alabama-Tennessee should refund to its Rate Schedule G–1 customers seven cents for each Mcf of billing demand with which customers have been charged since April 5, 1960, and which they have paid to Alabama-Tennessee and 1.9 cents for each Mcf of natural gas, as a commodity, paid by the said Rate Schedule G–1 customers at the 28.7 cents per Mcf rate which was also made effective April 5, 1960. It has been determined that for each Mcf of gas sold and delivered under the rates to SG–1 customers made effective April 5, 1960, Alabama-Tennessee should refund 10.1 cents, thus affecting a reduction in rate, from the 62 cents rate collected from such customers since April 5, 1960, to 51.9 cents per Mcf. No refund is presently required in the case of the Rate Schedule I–1 customers.

It has also been determined that Alabama-Tennessee shall and must file new rates for the sale of natural gas to its Rate Schedule G–1 customers in the amount of $3.48 of billing demand and 26.5 cents per Mcf of gas sold. Alabama-Tennessee shall also file new rates providing for the sale of natural gas to its SG–1 customers in the future at 51.9 cents per Mcf.

The increase in the demand rates of Tennessee contained in Tennessee's rate increase proposal, designated by this Commission as Docket No. G–19983 has resulted in a proposal by Alabama-Tennessee, in its proposed rates and charges considered in Docket No. G–19984, to increase its demand charge to its Rate Schedule G–1 customers by 85 cents per Mcf of billing demand to a total billing demand charge of $3.55 per Mcf monthly. The only other increase in billing demand involved in these four consolidated proceedings was that contained in Alabama-Tennessee's rate case filing designated as Docket No. G–11982.

In the case of Docket No. G–11982, Alabama-Tennessee reached an agreement with all of its jurisdictional customers except the City of Corinth, which agreement, not being unanimous, was not considered by this Commission. Alabama-Tennessee did, however, in its next rate increase filing (designated as Docket No. G–17218) propose to revert to the previous demand charge of $2.70 per month per Mcf of billing demand. This maintenance by Alabama-Tennessee, of the $2.70 per month demand charge, in spite of Tennessee's increase of 20 cents per month in its demand charge (as proposed in Tennessee's Docket No. G–11980 rate-increase application and collected by Tennessee from Alabama-Tennessee since July 14, 1957), has had the effect of reversing to some extent the tilt in favor of commodity as against demand, contained in Alabama-Tennessee's Rate Schedule G–1 rate prior to July 14, 1957. The subsequent filing of Alabama-Tennessee of the Docket No. G–17218 rates, which became effective May 15, 1959, further accentuated this change and resulted in an obvious tilt in favor of demand as against commodity in the G–1 rates of Alabama-Tennessee. Since, the SG–1 rate contains an arbitrary factor for demand based on an assumed 45 percent load factor, this rate (for each of the Docket Nos. G–11982 and G–17218 locked-in periods) reflects some of the increasing tilt toward demand as opposed to commodity which appears in the G–1 rates for the same period.

The proposal (designated as Docket No. G–19984) of Alabama-Tennessee to increase the demand portion of its G–1 rate by an amount equivalent to the increase of the demand portion of Tennessee's rate sought by that company in Docket No. G–19983, has permitted the making of an actual decrease in the allowed commodity rate of Alabama-Tennessee for the period, beginning April 5, 1960. This also has the effect of holding the increase in the SG–1 rate after April 5, 1960 to a minimal figure and increasing the margin between the Rate Schedule I–1 rate and the commodity portion of the G–1 rate. Both of the last mentioned effects improve the general balance of the rate structure of Alabama-Tennessee.

Further Findings and Conclusions

Upon consideration of the record made in these consolidated proceedings, including the pleadings, and the briefs and argument of counsel it is further found and concluded that:

(1) The proposed increased commodity rates contained in Alabama-Tennessee's First Revised Sheet No. 5 and in its First Revised Sheet No. 10 to its FPC Gas Tariff, First Revised Volume 1, filed November 5, 1954 and effective, subject to refund, from December 15, 1954 to July 13, 1957, are unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful and should be disallowed.

(2) The lawful rates and charges of Alabama-Tennessee for the commodity portion of the sale of natural gas to its Rate Schedule G–1 customers, subject to the jurisdiction of this Commission, for the period from December 15, 1954 through July 13, 1957 are 21.7 cents per Mcf or 1.45 cents per Mcf less than the rates and charges for the commodity portion of such service proposed in its First Revised Sheet No. 5 tendered for filing November 5, 1954.

(3) The lawful rates and charges of Alabama-Tennessee for sales of natural gas under its Rate Schedule No. SG–1, subject to the jurisdiction of this Commission, for the period December 15, 1954 through July 13, 1957 are 41.5 cents per Mcf or 1.15 cents per Mcf less than the proposed rate filed by Alabama-Tennessee, contained in its First Revised Sheet No. 10 of its FPC Gas Tariff First Revised Volume No. 1 for the period from December 15, through July 13, 1957.

(4) The rates and charges included in Original Sheets Nos. 8A, 8B, 8C, and 8D, filed December 29, 1955 and constituting Alabama-Tennessee's Rate Schedule TPS–G1, being part of its FPC Gas Tariff First Volume No. 1 and providing for temporary firm peak service to be effective from December 29, 1955 through April 30, 1956, are just and reasonable and not unduly discriminatory or preferential or otherwise unlawful.

(5) If and in the event that the rates and charges made by Alabama-Tennessee under the proposed increased rates filed by Tennessee in Docket No. G–5259 should hereafter be found to be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful and are disallowed in whole or in part and refunds made by Tennessee to Alabama-Tennessee in accordance with such whole or partial disallowance, then and in that event the increased rates included in Alabama-Tennessee's First Revised Sheets Nos. 5 and 10 to its FPC Gas Tariff Volume No. 1 may become unjust, unreasonable, unduly discriminatory or preferential to an extent greater than that found in Findings 2 and 3 above and further and additional refunds by Alabama-Tennessee to its jurisdictional customers may be required.

(6) The proposed rates and charges contained in Alabama-Tennessee's Third Revised Sheet No. 5 and Second Revised Sheet No. 10 to its FPC Gas Tariff First Revised Volume No. 1 tendered for filing on January 14, 1957 and made effective, subject to refund, as of July 14, 1957 are unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful and should be disallowed.

(7) The lawful rates and charges of Alabama-Tennessee for sale of natural gas to its G–1 customers, subject to the jurisdiction of this Commission, for the period from July 14, 1957 through May 14, 1959 are the proposed increased rates and charges, reduced from $2.90 per Mcf of billing demand to $2.70 per Mcf of billing demand or 20 cents per Mcf of billing demand, and the lawful rates and charges for commodity to said customers are the proposed increased rates, reduced from 25.05 cents per Mcf to 24.2 cents per Mcf, or .85 cents per Mcf for the period from July 14, 1957 through May 14, 1959. And the lawful rates and charges for the same period to the SG–1 customers of Alabama-Tennessee are the proposed increased rates, reduced from 46.75 cents per Mcf, to 43.9 cents per Mcf or a 2.85 cents per Mcf reduction thereof.

(8) The proposed increased rates and charges contained in Alabama-Tennessee's Original Sheet No. 11D to its FPC Gas Tariff, First Revised Volume No. 1 tendered for filing on March 1, 1957 and effective, subject to refund, from April 21, 1957 through May 14, 1959 are not unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful.

(9) In the event that Tennessee's rate increases proposed in Docket No. G–11980 which were effective, subject-to refund from July 14, 1957 through May 14, 1959 are hereafter found to be unjust, unreasonable, unduly dis-

criminatory or preferential or otherwise unlawful and that refunds of all or a portion of such increases are made by Tennessee to Alabama-Tennessee, then it is possible that all or part of the remaining proposed increased rates and charges of Alabama-Tennessee under Docket No. G–11982, collected from customers of Alabama-Tennessee subject to refund, may hereafter be found to be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful and should be disallowed, and, in that event, some further refunds by Alabama-Tennessee to its various classes of customers for the period when rates proposed in Docket No. G–11982 have been effective and collected by Alabama-Tennessee from said customers subject to refund, may be required.

(10) The proposed increased rates and charges contained in Alabama-Tennessee's Fourth Revised Sheet No. 5 and Fifth Revised Sheet No. 10 to its FPC First Revised Volume No. 1, tendered for filing November 14, 1958 and made effective, subject to refund, as of May 15, 1959 and continued in effect until April 4, 1960 are unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful and should be disallowed.

(11) The lawful rates and charges of Alabama-Tennessee for sales of natural gas, subject to the jurisdiction of this Commission, to Alabama-Tennessee's G–1 and SG–1 customers for the period May 15, 1959 to April 4, 1960 are the rates and charges proposed in the Docket No. G–17218 rate increase application, reduced by eight-tenths of a cent per Mcf in the case of G–1 customers and 1.1 cents per Mcf in the case of SG–1 customers.

(12) The proposed increased rates and charges contained in the First Revised Sheet No. 11D of Alabama-Tennessee's FPC Gas Tariff First Revised Volume No. 1, which became effective as of May 15, 1959, are hereby found not to be unjust, unreasonable, unduly discriminatory or preferential to Alabama-Tennessee's I–1 customers for the period extending from May 15, 1959 into the future and should not be disallowed, in the absence of any refund from Tennessee to Alabama-Tennessee for gas sold and delivered by Tennessee to Alabama-Tennessee during the said period.

(13) The rates and charges of Alabama-Tennessee to its I–1 customers during the period beginning May 15, 1959 may become unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful, if refunds are hereinafter ordered to be paid by Tennessee to Alabama-Tennessee in substantial amounts, for gas sold and delivered during the said period.

(14) The rates and charges of Alabama-Tennessee for service of Alabama-Tennessee's Rate Schedule G–1 and Rate Schedule SG–1 which are found to be presently lawful for the period from May 15, 1959 to April 4, 1960 in Finding (11) may hereafter become unjust, unreasonable, undully discriminatory, or preferential, or otherwise unlawful and subject to disallowance, in the event that substantial refunds are required to be made by Tennessee to Alabama-Tennessee for the service rendered to Alabama-Tennessee during the said period, under increased rates, subject to refund by order of this Commission issued in Docket No. G–17166.

(15) The proposed increased rates and charges contained in Alabama-Tennessee's Fifth Revised Sheet No. 5 and Sixth Revised Sheet No. 10 to its FPC Gas Tariff First Revised Volume No. 1, tendered for filing on October 5, 1959 and effective, subject to refund as of April 5, 1960 are unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful and should be disallowed.

(16) The presently lawful rates and charges of Alabama-Tennessee for sale of natural gas, subject to the jurisdiction of this Commission under Alabama-Tennessee's Rate Schedules Nos. G-1 and SG-1 for the period beginning April

5, 1960 are $3.48 per Mcf of billing demand and 26.5 cents per Mcf or 7 cents per Mcf of billing demand and 2.2 cents per Mcf of natural gas less than the rates proposed by Alabama-Tennessee in Docket No. G–19984, in the case of Rate Schedule G–1 customers, and 51.9 cents per Mcf, or 10.1 cents per Mcf of natural gas less than the rates proposed by Alabama-Tennessee in Docket No. G–19984, in the case of the SG–1 customers.

(17) In the event that the rates and charges of Tennessee to Alabama-Tennessee proposed in Docket No. G–19983 by Tennessee are hereafter found to be unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful and that such proposed rates of Tennessee are wholly or partially disallowed and substantial refunds by Tennessee to Alabama-Tennessee are hereafter paid, the presently lawful rates and charges of Alabama-Tennessee, discussed in the above Finding, may become unjust, unreasonable, unduly discriminatory or preferential or otherwise unlawful and further portions thereof should be disallowed.

(18) The motion of the Municipal Association to dismiss the four rate filings of Alabama-Tennessee under consideration in these consolidated proceedings on the ground that such filings are not authorized by the terms of the various service agreements between Alabama-Tennessee and its various distributors who are members of the said Municipal Association has not been shown to be justified and should be denied.

WHEREFORE, IT IS ORDERED, subject to review by the Commission that:

(A) The proposed increased rates and charges set forth in Alabama-Tennessee's First Revised Sheets Nos. 5 and 10 to its FPC Gas Tariff, First Revised Volume No. 1 for the period from December 15, 1954 through July 13, 1957, are hereby disallowed.

(B) Alabama-Tennessee shall, within sixty days of the time when this Decision becomes the official action of this Commission, refund to its G–1 customers, with interest at the rate of 6 percent per annum from the date of payment to Alabama-Tennessee to the date of refund, the excess of the total amounts charged and collected for sales made on and after December 15, 1954 through July 19, 1957, over the total amount which would have been charged to such customers under the lawful rates set forth in Finding (2) of this Decision, and Alabama-Tennessee shall bear the costs of such refunds.

(C) Alabama-Tennessee shall, within sixty days of the time when this Decision becomes the official action of this Commission, refund to its SG–1 customers, with interest at the rate of 6 percent per annum from the date of payment to Alabama-Tennessee to the date of refund, the excess of the total amounts charged and collected for sales made on and after December 15, 1954 through July 13, 1957, over the total amount which would have been charged to said customers under the lawful rates set forth in Finding (3) of this Decision, and Alabama-Tennessee shall bear the costs of such refunds.

(D) The proposed increased rates and charges set forth in Alabama-Tennessee's Third Revised Sheet No. 5 and Second Revised Sheet No. 10 to its FPC Gas Tariff, First Revised Volume No. 1 for the period from July 14, 1957 through May 14, 1959, are hereby disallowed.

(E) Alabama-Tennessee shall, within sixty days of the time when this Decision becomes the official action of this Commission, refund to its G–1 customers, with interest at the rate of 6 percent per annum from the date of payment to Alabama-Tennessee to the date of refund, the excess of the total amounts charged and collected for sales made on and after July 14, 1957 through May 14, 1959, over the total amounts which would have been charged to such customers under the lawful rates set forth in Finding (7) of this Decision, and Alabama-Tennessee shall bear the costs of such refunds.

(F) Alabama-Tennessee shall, within sixty days from the time when this Decision becomes the official action of this Commission, refund to its SG–1 customers, with interest at the rate of 6 percent per annum from the date of payment to Alabama-Tennessee to the date of refund, the excess of the total amounts charged and collected for sales made on and after July 14, 1957 through May 14, 1959, over the total amounts which would have been charged to such customers under the lawful rates set forth in Finding (7) of this Decision, and Alabama-Tennessee shall bear the costs of such refunds.

(G) The proposed increased rates and charges contained in Alabama-Tennessee's Fourth Revised Sheet No. 5 and Fifth Revised Sheet No. 10 to its FPC Gas Tariff, Revised Volume No. 1, for the period from May 15, 1959 through April 4, 1960, are hereby disallowed.

(H) Alabama-Tennessee shall, within sixty days from the time when this Decision becomes the official action of this Commission, refund to its G–1 customers and SG–1 customers with interest at the rate of 6 percent per annum from the date of payment to Alabama-Tennessee to the date of refund, the excess of the total amounts charged and collected for sales made on and after May 15, 1959 through April 4, 1960, over the total amounts which would have been charged to such customers (in each case) under the lawful rates set forth in Finding (11) of this Decision and Alabama-Tennessee shall bear the costs of such refunds.

(I) The proposed increased rates and charges contained in Alabama-Tennessee's Fifth Revised Sheet No. 5 and Sixth Revised Sheet No. 10 to its FPC Gas Tariff, First Revised Volume No. 1, for the period beginning April 5, 1960 are hereby disallowed.

(J) Alabama-Tennessee shall, within sixty days from the time when this Decision becomes the official action of this Commission, refund to its G–1 customers and SG–1 customers, with interest at the rate of 6 percent per annum from the date of payment to Alabama-Tennessee to the date of refund, the excess of the total amounts which would have been charged to such customers (in each case) under the lawful rates set forth in Finding (15) of this Decision and Alabama-Tennessee shall bear the costs of such refunds.

(K) The Commission retains jurisdiction over all of the rates being collected subject to refund in Docket Nos. G–5471, G–11982, G–17218 and G–19984, which are not herein ordered to be refunded, until determination of the lawful rates which should be paid by Alabama-Tennessee to Tennessee under the rate increase filings of Tennessee, under consideration in Docket Nos. G–5259, G–11980, G–17166 and G–19983, for the purpose of requiring such further refunds, if any, as may be required to be made by Alabama-Tennessee to its customers, which may result from possible reductions of Tennessee's rates and charges for the sale of gas to Alabama-Tennessee, and the right is reserved to adjust any further refunds by Alabama-Tennessee, which may result from determinations made in regard to the rates and charges of Tennessee, in such manner as to result in a differential not exceeding 2 cents per Mcf between the commodity element of the Rate Schedule G–1 rate and the Rate Schedule I–1 rate of Alabama-Tennessee.

(L) Alabama-Tennessee shall, within thirty days of the time when this Decision becomes the official action of the Commission, file tariff sheets in substitution for Fifth Revised Sheet No. 5 and Sixth Revised Sheet No. 10 of its FPC Gas Tariff, First Revised Volume No. 1, in accordance with the rates and charges found to be reasonable and proper charges in Finding (16) hereof.

(M) Within thirty days after making all the refunds provided for herein, Alabama-Tennessee shall report to the Commission, in writing and under oath, the amount of the refunds made to each of its jurisdictional customers, show-

ing separately the amount of principal and interest so paid, the billing determinants or other basis used for such determination and shall serve a copy of such report upon each of the customers receiving a refund.

(N) The motion of the Municipal Association to dismiss the four rate filings of Alabama-Tennessee under consideration in the consolidated proceedings is hereby denied.

GLEN R. LAW,
Presiding Examiner.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

CHAMPLIN OIL & REFINING COMPANY (OPERATOR), *et al.*, DOCKET NO. RI62-194

ORDER GRANTING MOTION FOR CLARIFICATION AND CLARIFYING PREVIOUS ORDER

(Issued June 13, 1962)

On May 4, 1962, Champlin Oil & Refining Company (Operator), *et al.*, (Champlin) filed a motion for clarification of the Commission's order issued November 22, 1961, in the above-entitled proceeding, providing for hearings on and suspension of proposed changes in rates and making rates effective subject to refund. The motion states that in Docket No. RI62-194 Champlin filed for an "estimated" increased rate of 14.7165¢ per Mcf [1] pursuant to a contractual right to be reimbursed by its buyer, Tennessee Gas Transmission Company (Tennessee), for three-fourths of the full amount of the Dedicated Reserve Gas Tax (Gas Tax) [2] which Champlin is required to pay to the State of Texas on those volumes of gas sold and delivered by Champlin to Tennessee at the San Salvador Field, Hildalgo County, Texas.[3] The notice of change was designated as Supplement 9 to Champlin's FPC Gas Rate Schedule No. 5.

The motion further states that by order issued November 22, 1961, the increased rate was allowed to become effective on December 2, 1961,[4] and since that time Champlin has submitted to Tennessee monthly charges which vary according to the amount of the Gas Tax which Champlin pays to the State of Texas. However, Champlin states that Tennessee has refused to pay any portion of the rate increase contending that the Commission's order of November 22, 1961, is ambiguous in that it is not clear whether the order constitutes authority for Champlin to charge a rate which varies according to the amount of the Gas Tax paid, or whether the order constitutes authority for Champlin to charge only the specific increased rate of 14.7165¢ per Mcf.

Where gas reserves are dedicated under a gas purchase contract, the Texas Dedicated Reserve Gas Tax is payable by the first purchaser of such gas at the rate of 1.0¢ per Mcf less the amount of the Texas Production Tax per Mcf. Because the amount of the Texas Production Tax may vary, the Texas Dedi-

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[1] This increased rate includes the previously effective rate of 14.6¢ per Mcf, plus an "estimated" increase of .1165¢ per Mcf for tax reimbursement.

[2] H.B. 20, Chapter 24, Article VI, Acts First Call Session, 57th Legislature of Texas, passed August 16, 1961, and made effective September 1, 1961.

[3] The order issued November 22, 1961, incorrectly states that the producing area for the subject gas is Stratton-Agua Dulce Field, Neuces and Jim Wells Counties, Texas (R.R. Dist. 4).

[4] The November 22 order suspended Champlin's rate increase for one day, and made it effective subject to refund on the condition that an acceptable agreement and undertaking was filed with the Commission within 20 days of the issuance of the order.

cated Reserve Gas Tax may also vary. In its notice of change, Champlin made it clear that the proposed increased rate was only estimated and that such rate might vary from time to time depending on the amount of tax actually payable by Champlin to the State of Texas.

Usually a natural gas company may charge and collect only a specified increased rate. However, in the special circumstances of this case, we deem it appropriate to permit Champlin to charge an increased rate that shall vary according to the amount of the Gas Tax paid by Champlin. To that end we shall clarify our suspension order of November 22, 1961.

The Commission finds:

(1) Champlin's motion for clarification should be granted as hereinafter ordered.

(2) The Commission's order of November 22, 1961, should be clarified to authorize Champlin, as of the time that the rate contained in Supplement No. 9 to its FPC Gas Rate Schedule No. 5 became effective subject to refund, to charge Tennessee a rate which varies according to the amount of the Gas Tax that Champlin pays to the State of Texas (i.e., the previously effective rate of 14.6¢ per Mcf, plus a tax reimbursement equal to three-fourths of the full amount of the Gas Tax which is paid by Champlin).

The Commission orders:

(A) The motion for clarification of Champlin Oil & Refining Company (Operator), *et al.*, is hereby granted.

(B) The Commission's order of November 22, 1961 is hereby clarified to authorize Champlin, as of the time that the rate contained in Supplement No. 9 to its FPC Gas Rate Schedule No. 5 became effective subject to refund, to charge Tennessee Gas Transmission Company a rate which varies according to the amount of the Gas Tax that Champlin pays to the State of Texas (i.e., the previously effective rate of 14.6¢ per Mcf, plus a tax reimbursement equal to three-fourths of the full amount of the Gas Tax which is paid by Champlin).

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

UNITED NATURAL GAS COMPANY, DOCKET NOS. G–12493, G–17763; THE SYLVANIA CORPORATION, DOCKET NO. G–12565

ORDER APPROVING RATE SETTLEMENT, PRESCRIBING REFUNDS AND TERMINATING PROCEEDINGS

(Issued June 13, 1962)

These consolidated proceedings arise under Sections 4 and 5 of the Natural Gas Act and involve the proposed increased rates and charges tendered for filing by United Natural Gas Company (United) in Docket Nos. G–12493 and G–17763 and also an investigation of the rates and charges of The Sylvania Corporation (Sylvania), United's affiliate. Both companies are wholly-owned subsidiaries of National Fuel Gas Company.

The proceeding in Docket No. G–12493 involves the revised tariff sheets tendered for filing by United on April 1, 1957, whereby it proposed to increase its rates and charges by $1,267,300 annually. These revised tariff sheets became effective subject to refund as of October 15, 1957.

The proceeding in Docket No. G–17763 involves the revised tariff sheets tendered for filing by United on January 5, 1959, whereby it proposed to further increase its rates and charges by $410,900 annually over and above the increase proposed in Docket No. G–12493. These revised tariff sheets became effective subject to refund as of May 15, 1959.

The proceeding in Docket No. G–12565 involves an investigation of the rates and charges of Sylvania which provides transportation and storage service and also sells natural gas to United, its affiliate.

On April 4, 1962, pursuant to consolidation and hearing notice, hearings were commenced. They were recessed from time to time, however, to permit settlement negotiations sought by the Company. On May 28, 1962, in hearing, counsel for United and Sylvania submitted for the record a stipulation and agreement, dated May 28, 1962, together with certain documents which included United's proposed offer of settlement dated March 19, 1962, and the cost of service studies prepared by the company and distributed to all parties on that date. Commission staff counsel also submitted for the record certain documents containing cost of service studies prepared by the staff and submitted to all parties to these proceedings for their consideration in the settlement negotiations which were held in Commission conference rooms during hearing recesses. The Presiding Examiner certified the record and the stipulation and agreement to the Commission for its consideration and concluded the hearing subject to further order of the Commission.

The record reflects the agreement of Peoples Natural Gas Company, Prospect Oil and Gas Company, Mercer Gas Light and Fuel Company, the Pennsylvania Public Utility Commission, and the two companies affiliated with United and Sylvania, Iroquois Gas Corporation and Pennsylvania Gas Company. The record also reflects the position of the City of Buffalo, New York, which is that while it "does not, as a matter of policy, accept stipulations and agreements in rate cases", it will abide by any order of the Commission issued in connection with this settlement agreement. The record also reflects that the Commission staff has agreed to the proposed settlement and recommends it to the Commission.

Briefly stated, the proposed settlement agreement provides as follows:[1]

(1) United shall file revised tariff sheets, to become effective as of April 1, 1962, reducing the rates subject to refund in Docket No. G–17763 for contract demand service (Rate Schedule CD–1) by 9.0¢ in demand to $2.81 per Mcf per month and by 0.5¢ in commodity to 38.5¢ per Mcf and for general service (Rate Schedule G–1) by 1.0¢ to 57¢ per Mcf. (Appendix B hereto)[2]

(2) United shall refund $999,984 plus interest at 6% per annum to its wholesale jurisdictional customers covering the period October 15, 1957, through December 31, 1961, of which $249,588 is applicable to the period October 15, 1957, through May 14, 1959, (Docket No. G–12493, Appendix C hereto page 1) and $750,396 is applicable to the period May 15, 1959, through December 31, 1961 (Docket No. G–17763, Appendix C, page 2). Further refunds shall be made by United covering the period from January 1, 1962, through March 31, 1962, computed on the difference between the contingent rates charged and the settlement rates (Appendix B hereto and paragraph (1) above). In addition to the said $999,984, United shall refund $300,016 to its wholesale jurisdic-

[1] For convenience only, Appendices A, B, C, and D to the proposed agreement are attached hereto. On both sheets of Appendix C there have been added certain appropriate sub-headings over each column of refund amounts.

[2] The settlement rates for the future are based upon an adjusted jurisdictional cost of service for the calendar year 1961 of $13,048,953, which is $226,098 less than the revenues collected during that year (Appendix B).

tional customers, which represents a flow-through of refunds (including interest) received from Texas Eastern Transmission Corporation and The Manufacturers Light and Heat Company (Appendix C, pages 1 and 2).

(3) If United receives a refund in the future, after March 31, 1962, from the six suppliers listed in Appendix D hereto, relating to the period October 15, 1957, through March 31, 1962, then United shall refund the jurisdictional portion of such amounts received (in the same manner as received, including interest received) except that United shall not be required to make any refunds out of amounts received until the accumulated amounts received total $50,000 or more, except for the final refund which need not be made if the amount refundable is less than $10,000.

(4) If any of the suppliers listed in Appendix D hereto are required to reduce their future rates below the rates used for the purpose of determining the 1961 cost of service (Appendix B hereto) utilized for the future in the settlement, then United shall file a reduction in the settlement rates (paragraph (1) above); provided that no such reduction need be made unless and until such reductions reduce the average weighted cost of purchased gas derived from the 1961 settlement cost of service by at least $50,000 per year; and provided, further, that if United is required to repay to any of its suppliers refunds received by it due to the invalidation by the courts of this Commission's refund orders, United will be permitted to offset such repayments against any refunds in hand or thereafter received from any of its suppliers until reimbursed for such repayment.[3]

(5) There will be a moratorium on the filing of further rate increases by United for a period of 18 months from the date of this order, except to recover increased costs resulting from (a) increased purchased gas costs on a weighted average basis related to the 1961 settlement cost of service (Appendix B), and (b) new taxes or increased tax rates which result in an annual increase of $50,000 or more in costs applicable to jurisdictional sales.

(6) No reductions shall be made in Sylvania's rates and charges.

(7) These consolidated proceedings be terminated upon approval of the agreement by the Commission; subject only to future refund and rate reduction provisions pursuant to Article III of the agreement (paragraph (3) and (4) of above summary).

(8) United shall file certain revised tariff sheets to modify its tariff provisions relating to limitations on deliveries and to substitute certain language relating to cancellation of service agreements. The agreement also contains additional provisions that it is conditioned upon the Commission's approval of its terms and conditions, that no party shall be considered as having agreed to any rate making principle or method, and that the parties request the Commission to waive compliance with its regulations insofar as it is necessary to carry out the provisions of the agreement.

The Commission finds:

(1) The proposed increased rates and charges which became effective on May 15, 1959, subject to hearing and refund in Docket No. G–17763, as hereinabove described, have not been shown to be just and reasonable, or otherwise lawful under the terms and provisions of the Natural Gas Act, and such rates and charges should be disallowed and denied as hereinafter provided and ordered.

[3] United's counsel, in hearing on the record stated that the only instance in which it is intended that the right to offset repayments of refunds, would arise, due to invalidation of refunds by the courts, would be that arising from the Commission's interim order issued August 9, 1960, in Tennessee Gas Transmission Company, Docket No. G–19983 [24 FPC 204].

(2) The settlement of these consolidated proceedings on the basis proposed and agreed to by the parties and certified to us by the Presiding Examiner for our consideration, as above described and as more specifically set forth in said stipulation and agreement, is reasonable and proper in the public interest in carrying out the provisions of the Natural Gas Act and such proposed settlement agreement should be approved and be made effective, subject to the terms and conditions hereinafter provided and ordered.

The Commission orders:

(A) The proposed increased rates and charges contained in the rate filings referred to in paragraph (1) above, are disallowed and denied.

(B) The settlement of these consolidated proceedings on the basis and terms contained in the settlement agreement as hereinabove described, is approved and made effective, subject to the terms and conditions hereinafter ordered.

(C) United shall, within 45 days of the date of this order, make refunds of excess charges currently due to its jurisdictional customers, including interest thereon from the dates of payment of such excess charges until the date of mailing payments of such refunds, as provided in Articles I, II, and III, as described hereinabove in paragraphs (2), (3) and (4) of the above summary of the agreement, and as partly set forth in Appendix C hereto.

(D) United shall make future refunds and necessary rate reductions to reflect refunds and rate reductions of its suppliers, as provided in Article III of said agreement, and as described in paragraphs (3) and (4) of the above summary of the agreement, subject to the approval of the Commission.

(E) Within 20 days after refunds have been made as provided in paragraph (C) hereof, United shall report to the Commission, in writing and under oath, the amount of the refunds (including interest), made to each of its utility customers (in sufficient detail) to enable verification of the manner in which such refunds were computed), and shall serve a copy of such report upon each of its said customers receiving a refund. Concurrently therewith, United shall file with the Commission releases from its jurisdictional customers showing receipt of principal and interest so paid.

(F) Upon payment of the amounts of refunds provided in Article III of the agreement, and upon compliance with the terms and conditions of paragraphs (C) and (E) of this order, the proceedings in Docket Nos. G–12493, G–17763, and G–12565 shall be terminated, subject only to United's obligations under paragraph (D) and (E) hereof and under Article III of the agreement relating to such future refund and rate reduction obligations.

(G) Nothing contained in this order shall be construed as a waiver of the requirements of Section 7 of the Natural Gas Act, as amended; nor shall it be construed as constituting approval by this Commission of any service, rate, charge, classification, or any rule, regulation, contract or practice affecting such service or rate provided for in the above-described tariff sheets; nor shall this order be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate.

(H) This order is without prejudice to any findings or orders which have been or may hereafter be made by the Commission and is without prejudice to any claims or contentions which may be made by the Commission, United, Sylvania, the Commission staff, or any other party affected by this order, in any proceeding now pending or hereafter instituted by or against United or Sylvania or any other persons or parties affected by this order.

APPENDIX A

UNITED NATURAL GAS COMPANY, DOCKET NO. G–17763

Year 1961 summary cost of service (Exclusive of Distribution)

Operating expenses:	
Production:	
Purchased gas	$22, 844, 772
Gas delivered to storage (credit)	(5, 236, 219)
Gas withdrawn from storage	4, 989, 300
Other production expenses	1, 164, 748
Total production	23, 762, 601
Storage	699, 126
Transmission	805, 739
Administrative and general expenses	710, 480
Total operating expenses	25, 977, 946
Depreciation and depletion	914, 938
Taxes other than income	260, 354
Pennsylvania State income taxes	174, 958
Federal income taxes	1, 419, 905
Return 6.5%	1, 973, 671
Subtotal	30, 721, 772
Other gas revenues (credit)	(86, 922)
Total cost of service	30, 634, 850

APPENDIX B

UNITED NATURAL GAS COMPANY, DOCKET NO. G–17763

Allocation of cost of service for calendar year 1961 and determination of prospective rates

		Total	Demand	Commodity
1	Total cost of service	$30, 634, 850	$7, 891, 525	$22, 743, 325
2	Allocation factor—percent		36. 743311	44. 559645
3	Jurisdictional cost of service	$13, 033, 953	$2, 899, 608	$10, 134, 345
4	Regulatory commission expense	15, 000	7, 500	7, 500
5	Adjusted jurisdictional cost of service	13, 048, 953	2, 907, 108	10, 141, 845
6	Jurisdictional revenue collected	13, 275, 051		
7	Excess revenue (Line 6 minus line 5)	226, 098		
8	Billing determinants (Mcf)		[1] 1, 049, 845	26, 234, 979
9	Unit costs (Per Mcf)		$2. 769	38. 6577¢
10	Prospective rates (Per Mcf):			
	Rate Schedule CD–1		$2. 81	38. 5¢
	Rate Schedule G–1 [2]			57. 0¢

[1] Billing demand units for G–1 customers imputed at 50% load factor.
[2] Equivalent to 50% load factor charge under Rate Schedule CD–1.

APPENDIX C

UNITED NATURAL GAS COMPANY

Refunds to be made to customers not including United's interest liability

Customer	Rate Schedule	Docket G-12493			
		Oct. 15, 1957 through May 14, 1959			
		Cost of service	Texas Eastern	Manufacturers	Total
Iroquois Gas Corporation	CD-1	196,406.25	149,922.61	13,106.18	359,435.04
Pennsylvania Gas Company	CD-1	34,889.72	26,632.95	2,328.19	63,850.86
Andover Gas Company	G-1	556.35	415.32	37.12	1,008.79
Mercer Gas Light & Fuel Company	G-1	3,022.28	2,321.06	201.68	5,545.02
Prospect Oil & Gas Company	G-1	971.76	742.39	64.85	1,779.00
The Peoples Natural Gas Company	G-1	13,741.64	10,542.67	916.98	25,201.29
Total		249,588.00	190,577.00	16,655.00	456,820.00

APPENDIX C

UNITED NATURAL GAS COMPANY

Refunds to be made to customers not including United's interest liability

Customer	Rate Schedule	Docket G-17763				
		May 15, 1959 through Dec. 31, 1961				
		Cost of service	Purchased Gas adjustment	Texas Eastern	Manufacturers	Total
Iroquois Gas Corporation	CD-1	453,233.50	146,689.08	67,742.62	7,541.02	675,206.22
Pennsylvania Gas Company	CD-1	69,324.07	22,443.37	10,707.55	1,191.95	103,666.94
Mercer Gas Light & Fuel Company	G-1	7,905.56	3,930.82	728.57	81.10	12,646.05
Prospect Oil & Gas Company	G-1	2,020.15	1,028.49	135.64	15.10	3,199.38
The Peoples Natural Gas Company	G-1	30,195.72	13,625.24	4,175.62	464.83	48,461.41
Total		562,679.00	187,717.00	83,490.00	9,294.00	843,180.00

APPENDIX D

UNITED NATURAL GAS COMPANY

Natural gas suppliers from whom refunds may be received under the listed dockets

Supplier	*Docket Nos.*
Iroquois Gas Corporation	G-13389.
Iroquois Gas Corporation (Tennessee Gas Transmission Co. Transportation).	G-11980, G-19983.
McCoy Natural Gas Company	G-18363.
New York State Natural Gas Corporation	G-17296, G-19087.
The Manufacturers Light and Heat Company	G-12197, G-16820, G-18425, G-19250, G-20510.
Tennessee Gas Transmission Company	G-11980, G-17166, G-19983.
Texas Eastern Transmission Corporation	G-12706, G-18841.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

CHUGACH ELECTRIC ASSOCIATION, INC., PROJECT NO. 2170

ORDER FURTHER AMENDING LICENSE (MAJOR)

(Issued June 14, 1962)

Application was filed January 9, 1961 by Chugach Electric Association, Inc., licensee for major Project No. 2170, to be located on Cooper Lake, Cooper Creek and Kenai Lake, Alaska, for further amendment of its license for the proposed project so as to authorize a change in a portion of the route of the Cooper Lake —Anchorage 115 kv transmission line from the presently authorized route shown on Exhibit J (FPC No. 2170-14) now approved as part of license issued May 27, 1957, 17 FPC 759.

The project affects lands of the United States within the Chugach National Forest.

The license presently authorizes a transmission line route originating at the Cooper Lake Hydroelectric plant of Chugach, and extending northward to Snipers Point on the south shore of Turnagain Arm (an arm of Cook Inlet), and thence by an aerial cable 2.5 to 3.0 miles in length to Bird Point on the north shore, and, finally, northwesterly to Anchorage.

The application for amendment requests authorization to eliminate the aerial cable across Turnagain Arm and in lieu thereof reroute the line around the head of Turnagain Arm. The licensee advises that the proposed route is more feasible and will result in a savings of approximately $700,000 in construction costs.

The Secretary of Agriculture, in reporting on the application, has advised that, provided certain recommended special conditions are included in the license as further amended, his Department finds that the transmission line located along the route as proposed in the subject application for amendment will not interfere or be inconsistent with the purpose for which the Chugach National Forest was created or acquired. We are hereinafter including in the license the recommended special conditions.

The Commission finds:

The license, further amended as hereinafter provided, will not interfere or be inconsistent with the purposes for which the Chugach National Forest was created or acquired, and will not alter any of the basic facts upon which the license was issued.

The Commission orders:

(A) The license for proposed Project No. 2170 is hereby further amended, effective as of June 1, 1962, as follows:

PARAGRAPH I. Finding (2) (b) of the license is amended by inserting after the word "Anchorage" in the 8th line of page 3 of the license the words "via Hope Junction, Johnson's Pass and Bird Point."

PARAGRAPH II. The following new articles are added to the license:

Article 32. The Licensee shall construct the transmission line on the location which has been prescribed and referenced on the ground by the U. S. Forest Service. Any deviation from this route must have the approval of the Forest Supervisor prior to the start of construction.

Article 33. The Licensee shall not clear any portion of the right-of-way until the width of clearing has been prescribed and mutually agreed upon by the U. S. Forest Service and the Licensee.

Article 34. It is recognized that others may construct electric generating facilities which may require transmission facilities to be constructed along a portion or portions of the route of the transmission facilities constructed by the Licensee pursuant to this license. To prevent unnecessary duplication of transmission facilities, the Licensee shall, when ordered to do so by the Commission, and based upon recommendations of the U. S. Forest Service: (1) wheel electric power and energy of such others over its transmission facilities to the extent and as long as the Licensee shall have surplus capacity available in its transmission facilities for such purpose, or (2) enter into an agreement with such others for the joint use of its transmission poles upon terms, conditions, and charges to be established by the Commission, subject to adequate provisions for (1) payments by such others for necessary construction to carry out the wheeling or joint-use agreement, and (2) protection of the Licensee's service area and noninterference by such others in the Licensee's operations.

Article 35. The Licensee shall perform such erosion control and other measures as are necessary to restore to a condition satisfactory to the U. S. Forest Service the cleared lands on the route originally authorized by this license between Frenchy Creek and Snipers Point. Such measures shall be prescribed by the U. S. Forest Service and performed by the Licensee at the earliest practicable date and not later than September 1, 1962.

PARAGRAPH III. This amendment in the manner set out above shall not operate to alter or amend the license in any other respect, and shall not in any way constitute a waiver of any other part, provision or condition of the license.

(B) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313 (a) of the Act, and failure to file such an application shall constitute acceptance of this license amendment. In acknowledgment of the acceptance of this license amendment, it shall be signed for the licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

CIMARRON TRANSMISSION COMPANY, DOCKET NO. CP62-234

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 14, 1962)

On April 2, 1962, Cimarron Transmission Company (Applicant) filed in Docket No. CP62-234 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction during the calendar year 1962 of field facilities and the operation thereof to enable Applicant to take into its certificated main pipeline system natural gas which may be purchased from producers thereof, all as more fully set forth in the application.

The purpose of this "budget-type" application is to augment Applicant's ability to act with reasonable dispatch in contracting for and connecting to its pipeline system new supplies of natural gas in various producing areas generally coextensive with said system.

The total cost of the proposed facilities will not exceed $75,000, and no single project will exceed a cost of $15,000. The subject facilities will be financed from cash on hand, from cash generated from normal operations and internal sources, and from financing already arranged.

Pursuant to due notice, a public hearing was held in Washington, D. C., on June 5, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30(c)(1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Cimarron Transmission Company, an Oklahoma corporation having its principal place of business in Tulsa, Oklahoma, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of December 17, 1959, in Docket No. G–17014, *et al.* (22 FPC 1059).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are proposed to be used in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of facilities to take natural gas purchased from producers thereof as proposed by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(6) It is necessary and appropriate in carrying out the provisions of the Natural Gas Act that Applicant should submit, on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects that have been constructed pursuant to the authorization hereinafter granted, (d) the location of said project or projects, (e) the actual final costs of said facilities, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(7) The authorization hereinafter granted should be limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed thereunder should be limited to a maximum of $75,000, with no single project to exceed a cost of $15,000.

(8) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Upon the terms and conditions of this order, a certificate of public convenience and necessity be and the same is hereby issued authorizing Cimarron Transmission Company to construct during the calendar year 1962 the proposed facilities hereinbefore described, as more fully described in the application in this proceeding, and to operate the facilities only to take natural gas supplies from producers who have received authorization from the Commission to sell natural gas to Cimarron Transmission Company.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(C) Applicant shall submit on or before March 1, 1963, a statement under oath showing by projects: (a) names of fields connected, (b) estimates of gas supplies attached, (c) a description of the project or projects constructed pursuant to the authorization hereinbefore granted, (d) the location of said project or projects, (e) the actual final costs of said facilities, and (f) the names of the independent producers involved, together with the respective dates of the gas sales contracts and the docket numbers of the related producer certificate applications.

(D) The authorization granted in paragraph (A) above is hereby limited to construction during the calendar year 1962, and the total expenditures for facilities to be constructed thereunder are hereby limited to a maximum of $75,000, with no single project to exceed a cost of $15,000.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

COASTAL TRANSMISSION CORPORATION, *ET AL.* DOCKET NO. G–18338, *ET AL.*

ORDER FURTHER AMENDING ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 14, 1962)

On February 19, 1962, as supplemented on March 30, 1962, Coastal Transmission Corporation (Coastal) and Florida Gas Transmission Company (Florida Gas) (formerly Houston Texas Gas and Oil Corporation) filed a joint motion to amend the Commission's order issued August 9, 1961, in Docket Nos. G–18338, *et al.*, 26 FPC 318, as further modified by order issued November 2, 1961, 26 FPC 677, in respect to the certificates of public convenience and necessity granted to Coastal and Florida Gas in Docket Nos. G–18338 and G–18615, respectively, all as more fully set forth in the aforesaid motion and supplement.

The requested amendments to the subject certificate authorizations are as follows:

(1) Florida Gas, in Docket No. G–18615, to construct and operate approximately 9.3 miles of 4½-inch lateral pipeline from a point on its 20-inch main transmission line in Indian River County, Florida, to the site of a new electric generating plant in the City of Vero Beach, Florida, in lieu of the presently authorized approximately 6 miles of 2⅞-inch lateral pipeline to the site of the old City of Vero Beach electric generating plant. This proposed change is esti-

mated to increase the cost of the Vero Beach lateral from $115,700 to $196,300, or an additional $80,600.

(2) To delete from Coastal's authorization in Docket No. G–18338 the following facilities which Coastal does not propose to construct and operate: (a) Fulton Beach Tap, (b) Potrero Lopena 14.2-mile lateral pipeline, and (c) Palacios Lateral 1.2-mile extension lateral to facilities of Socony, Mobil Oil Company. The estimated total cost of these facilities was $458,695.

(3) Coastal, in Docket No. G–18338, to construct and operate a 1.3-mile addition to the Palacios Lateral system extending from the new terminus of the Palacios Lateral to the Tenneco (Tennessee Gas Transmission Company) processing plant in Matagorda County, Texas, at an estimated cost of $39,000.

(4) Coastal, in Docket No. G–18338, to construct and operate approximately 6.1 miles of 8-inch loop pipeline from the end of the presently authorized 6.0 miles of 8-inch loop on the Palacios Lateral to the aforesaid new terminus thereof, at an estimated total cost of $174,400.

(5) Coastal, in Docket No. G–18338, to increase the size of the presently authorized approximately 16 miles of 8-inch pipeline comprising the so-called Lake Chicot Lateral in St. Martin and Iberia Parishes, Louisiana, to approximately 11.1 miles of 10-inch pipeline and 4.9 miles of 12-inch pipeline. This proposed change is requested to provide sufficient capacity in the subject lateral to permit further development of the field which it serves. Said change is estimated to increase the cost of the Lake Chicot Lateral from $836,489 to $960,000, or an additional $123,511.

(6) Florida Gas, in Docket No. G–18615, (by the Supplement filed on March 30, 1962, to the February 19, 1962, motion to amend) to increase the size of the presently authorized approximately 32 miles of 6⅝-inch pipeline comprising the so-called Indian River Lateral extending from Florida Gas' 20-inch main transmission line to the Indian River electric generating plant of the Orlando Utilities Commission near Delespine, Brevard County, Florida, to a diameter of 8⅝-inches. This proposed change is requested to provide sufficient capacity in the subject lateral to take care of indicated future requirements which exceed those expected at the time of the original application. Said change is estimated to increase the cost of the Indian River Lateral from the original figure of $744,016 to $856,000, or an additional $111,984.

Notice of the filing of the aforesaid joint motion to amend was published in the Federal Register on May 25, 1962 (27 FR 4944). No protest, petition to intervene or request for hearing has been received.

On March 14, 1962, Florida Gas filed a motion to amend the Commission's order issued November 2, 1961, in Docket Nos. G–18338, *et al.*, to reflect the change in franchise of particular customers proposed to be served under the existing authorization, as follows: (1) from the City of Boca Raton, Florida, to the Florida Public Utilities Company, and (2) from the Pompano Natural Gas Company to the City Gas Company of Florida. Construction of the authorized facilities for these two services had not begun as of March 14, 1962, but no change in the construction authorization is proposed. On March 29, 1962, Florida Gas filed a notice of withdrawal of that portion of the March 14 motion for amendment relating to Pompano Natural Gas Company due to a local controversy in which Florida Gas is not involved.

The Commission finds:

It is necessary and appropriate in carrying out the provisions of the Natural Gas Act and the public convenience and necessity require that the order of the Commission issued August 9, 1961, in Docket Nos. G–18338, *et al.*, as modified by order issued November 2, 1961, be further amended as hereinafter ordered.

The Commission orders:

(A) The order of the Commission issued August 9, 1961, in Docket Nos. G–18338, *et al.*, as modified, be and the same is hereby further amended to reflect and authorize the changes set forth as Items (1) to (6), inclusive, hereinabove.

(B) Said order be and the same is hereby further amended by substituting Florida Public Utilities Company for the City of Boca Raton, Florida, as the purchasing distributor of natural gas for the Boca Raton area.

(C) In all other respects, said order of August 9, 1961, in Docket Nos. G–18338, *et al.*, as previously modified, shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

SIERRA PACIFIC POWER COMPANY, DOCKET NO. E–7031

ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTGAGE BONDS

(Issued June 14, 1962)

Sierra Pacific Power Company (Applicant), a corporation organized under the laws of the State of Maine and doing business in the States of California and Nevada, with its principal place of business at Reno, Navada, filed an application on March 29, 1962, as amended on April 17 and 21 and on May 11 and 28, 1962, for an order or orders, pursuant to Section 204 of the Federal Power Act, authorizing the issuances of: (1) Short-term Promissory Notes in the aggregate principal amount of not in exceess of $5,000,000 outstanding at any one time, and (2) $5,000,000, principal amount of First Mortgage Bonds, due 1992. By order issued May 16, 1962, 27 FPC 965, in the above-named docket, the Commission authorized the issuance of the afore-mentioned Promissory Notes. By amendment filed May 11, 1962, Applicant now requests that an order be issued authorizing the proposed issuance and sale at competitive bidding of the afore-mentioned First Mortgage Bonds.

Applicant proposes to issue the Bonds under its Indenture of Mortgage, dated December 1, 1940, as heretofore supplemented and as to be further supplemented by an Eighth Supplemental Indenture dated as of June 1, 1962, between Applicant and New England Merchants Bank of Boston and Fletcher C. Chamberlin, Trustees.

Applicant proposes, on or about June 19, 1962, to publicly invite sealed, written bids for the purchase of the proposed Bonds, by newspaper publication and by distribution of a Form of Proposal, together with a Statement of Terms and Conditions relating thereto and a Form of Purchase contract. All bids, whether from a single bidder or a group of bidders, must be for the purchase of the entire issuance of Bonds and must be on the Form of Proposal provided by Applicant. Each bid must specify, among other things: the interest rate to be borne by the Bonds, which rate shall be a multiple of ⅛th of 1 percent; the price exclusive of accrued interest to be paid to Applicant for the Bonds, which price shall be not less than 100% and not more than 102¾% of the principal amount thereof; in the case of a bid by a group of bidders, the principal amount of the Bonds to be purchased by each member of the group; and, that Applicant shall be paid the amount of the accrued interest on the Bonds from June 1, 1962 to the date of payment therefor and delivery thereof.

Unless postponed all bid for the purchase of the proposed Bonds must be presented in duplicate to Applicant at 49 Federal Street (8th Floor), Boston,

Massachusetts, before 11:00 a.m., Boston Time, on June 26, 1962. Applicant, unless it rejects all bids or excludes a bid or bids for reasons specified in the Statement of Terms and Conditions, will accept the bid which provides for the lowest annual cost of money. Each bid must be accompanied by a certified, bank cashier's, or trust company treasurer's check or checks in the aggregate amount of $150,000, payable in Boston or New York Clearing House funds.

Applicant will use the net proceeds from the sale of the proposed Bonds for the payment of short-term bank loans then outstanding and to finance in part Applicant's 1962 construction program. By order issued May 16, 1962 in this docket Applicant was authorized to issue Short-term Promissory Notes aggregating in principal amount not in excess of $5,000,000 outstanding at any one time and maturing not later than September 30, 1962. Applicant expects that it will have short-term Notes in the aggregate principal amount of approximately $3,400,000 outstanding at the time of the sale of the proposed new Bonds. Principal items of expenditure for Applicant's 1962 construction program, estimated to cost $11,659,900, are, as follows: $2,898,000 for continuing installation of Unit No. 1 and $1,014,000 for gas turbines, at Applicant's Frank A. Tracy Station, 17 miles east of Reno; $1,170,100 for transmission lines and substations, including $340,000 for the Buckeye-Tahoe Valley 120 kv line (total cost estimated at $540,000, to be completed in 1963) and $344,600 for the 120 kv Brunswick-Minden line; $3,048,900 for improvements to power plants, transmission and distribution system, for distribution and transmission substations, and for extensions, meters, services and transformers needed to serve new customers; $2,016,000 for extensions and improvements to existing facilities, reservoirs and flumes of Applicant's water department; $386,100 for Applicant's gas department; and $1,064,400 for general plant.

Written notice of the application has been given to the California Public Utilities Commission and the Nevada Public Service Commission, and to the Governor of each of those States. Notice of the application was also given by publication in the Federal Register on April 7, 1962 (27 F.R. 3362), stating that any person desiring to be heard or to make any protest with reference to the application should file a petition or protest on or before the 24th day of April, 1962 with the Federal Power Commission, Washington 25, D. C. No protest or petition or request to be heard in opposition to the granting of the application has been received.

The Commission finds:

(1) Applicant, a corporation, is a public utility within the meaning of Section 204 of the Federal Power Act, subject to the jurisdiction of the Commission as heretofore described and set forth in the Commission's order issued May 2, 1961, *Sierra Pacific Power Company*, Docket No. E-6984 (25 FPC 904).

(2) The proposed issuance and sale of Bonds, as described above, will constitute an issuance of securities within the purview of Section 204 of the Act.

(3) Applicant is not organized and operating in a State under the laws of which the security issue here involved is regulated by a State commission within the meaning of Section 204(f) of the Act; and the proposed issuance of securities is, therefore, not exempt by virtue of that Section from the requirements of Section 204 of the Act.

(4) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of Applicant and compatible with the public interest, which is appropriate for and consistent

with the proper performance by Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purposes.

The Commission orders:

(A) The proposed issuance and sale of Bonds, upon the terms and conditions and for the purposes specified in the application, as described above, are authorized, subject to the provisions of this order.

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2(k)(3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2(k)(4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

(C) This authorization shall expire unless the transaction hereby authorized is consummated within 60 days from the date of issuance of this order.

(D) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(E) Nothing in this order shall be construed to imply any guarantee or obligation on the part of the United States with respect to any securities to which this order relates.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

ALABAMA POWER COMPANY, PROJECT NO. 2146

ORDER FURTHER AMENDING LICENSE (MAJOR)

(Issued June 15, 1962)

Application was filed on September 16, 1960, and supplemented on November 30, 1960, by Alabama Power Company, licensee for major Project No. 2146, for further amendment of its license for the project situated on the Coosa River, navigable waters of the United States and affecting lands of the United States.

The application as supplemented proposes revision of Article 41 of the license to authorize the raising of the normal operating water surface of Logan Martin Reservoir from elevation 460 to 465 feet and to make minor changes in the name-plate ratings of the two authorized turbines and generators to be installed in the powerhouse.

On June 16, 1961, the licensee filed application for further amendment of the license for authorization to install the third generating unit in the Logan Martin Development during initial construction.

The Logan Martin Development was formerly known as the Kelly Creek Development.

Recent load forecast and power supply studies, obtained by taking detail load forecasts for 1962, 1963 and 1964 from each of the four operating com-

panies forming the Southern integrated system and developing therefrom a diversified system total, indicate that the power output from the Logan Martin development, constructed initially to its ultimate capacity of 128,250 kilowatts (3-units of 42,750 kilowatts each), will be required to meet the estimated 1964 system load and its dependable capacity thereon is estimated at 125,300 kw. The average annual energy to be obtained from the ultimate installation is estimated at 392.8 million kwh. The capital cost of the ultimate development, constructed initially, is estimated at $34,759,000. Based on power values of $26.73 per kw-year for dependable capacity and 2.30 mills per kwh for average annual energy, the estimated annual value of the power output is about $4,255,000. The annual cost of the ultimate development, constructed initially, is estimated at $4,082,000—hence the annual net benefits therefrom amount to about $173,000.

The effect of granting the applications will be reflected in the description of the project works of the Logan Martin Development, in the amount of administrative annual charges payable under the license, and in Article 41 pertaining to the operating level of the Logan Martin Reservoir.

The Chief of Engineers and the Secretary of the Army have reported that the raising of the Logan Martin reservoir is satisfactory insofar as the interests of navigation and flood control are concerned and additional terms and conditions in the interest of navigation or flood control are not considered necessary for inclusion in any amendment issued. Revised plans of the structures affecting navigation or flood control have been approved in accordance with Section 4(e) of the Federal Power Act.

An Assistant Secretary of the Interior has reported that the raising of the Logan Martin reservoir would not have any adverse effect on the fish and wildlife resources of the area involved.

The Commission finds:

(1) The license, further amended as hereinafter provided, will not interfere or be inconsistent with any reservation or withdrawal of lands of the United States and is in the public interest.

(2) Public notice of the September 16, 1960 application has been given. No protests have been received.

(3) The authorized installed horsepower capacity of the project for the purpose of computing the capacity component of the administrative annual charge is 724,000 horsepower, and the increased annual charge for reimbursing the United States for the costs of administration of Part I of the Federal Power Act, based on such capacity, as hereinafter provided, is reasonable.

(4) The following described revised exhibits conform to the Commission's rules and regulations and should be approved as part of the license and the exhibits described herein as being superseded should be eliminated from the license for the project:

Exhibit L	FPC No.	Logan Martin Development
Revision No. 2. Sheet No. 10.	2146-162	Plan, Dike & Spillway Section.
Revision No. 3. Sheet No. 10A.	2146-168	Powerhouse Transverse Section.
Revision No. 1. Sheet No. 10A-1.	2146-169	Powerhouse—Transverse Section.
Revision No. 3. Sheet No. 10B.	2146-170	Powerhouse Longitudinal Section.
Revision No. 3. Sheet No. 10C.	2146-171	Powerhouse Floor Plans.
Revision No. 3. Sheet No. 10D.	2146-172	Powerhouse Floor Plans.

superseding Exhibit L-Revised, sheets Nos. 10, 10A, 10B and 10C (FPC Nos. 2146–136 through –139);

> Exhibit M (Revision No. 2) entitled "General description of mechanical, electrical and transmission equipment;"

superseding Exhibit M, now part of the license, insofar as it relates to the Logan Martin (Kelly Creek) development; and

> Exhibit H, Fig. 2-A, a rule curve showing the seasonal variation of the power pool elevation of the Logan Martin reservoir between elevations 460 feet and 465 feet;

superseding Exhibit H, Fig. 2, now part of the amended license.

The Commission orders:

(A) The exhibits described in finding (4) above as conforming to the Commission's rules and regulations are approved as part of the license for the project and the exhibits described in the same finding as being superseded are eliminated from the license for the project.

(B) Th license for Project No. 2146 is further amended, effective as of June 1, 1962, as follows:

PARAGRAPH I: Finding (2) (b) (iii) is amended to read as follows:

> (iii) *The Proposed Logan Martin (Kelly Creek) Development*
> A dam comprised of a concrete gated spillway and powerhouse section and compacted earth abutment dikes; a reservoir, with full power pool elevation 465 feet and an area of about 15,300 acres extending 49.1 miles upstream to Lock 3 dam, having a 5-foot drawdown providing usable power storage of about 74,000 acre-feet and controlled surcharge storage between elevations 460 and 474.6 feet for control of floods; a powerhouse with three 57,000-horsepower turbines connected to three 42,750-kilowatt generators; a substation; and appurtenant electrical and mechanical facilities;

PARAGRAPH II. Article 28 of the license is further revised to show the authorized installed capacity as being increased to 724,000 horsepower.

PARAGRAPH III. Article 41 of the license is amended to read as follows:

Article 41. The Licensee shall make available on a seasonal basis as shown on the rule curve designated as Exhibit H, Fig. 2A, in the application for amendment of license filed September 16, 1960 (which exhibit is incorporated as a part of this license), the storage between elevations 460 and 465 feet in the Logan Martin Reservoir (formerly designated as Kelly Creek Reservoir) for flood control use. For regulating floods comparable to those of record (1929 to 1950), storage will be utilized for induced surcharge operations up to elevation 474.6 feet, and to higher elevations as required to compensate for lost valley storage during greater floods, with the details of operation specified by rules and regulations prescribed by the Secretary of the Army from time to time.

(C) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313 (a) of the Federal Power Act, and failure to file such an application shall constitute acceptance of this amendment of license. In the acknowledgment of the acceptance of this amendment of license, it shall be signed for the licensee and returned to the Commission within 60 days from the date of issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

ARKANSAS-LOUISIANA GAS COMPANY, DOCKET NO. G–17567; ILLINOIS POWER COMPANY, DOCKET NO. G–17984; ST. CHARLES GAS CORPORATION, G–18405; LACLEDE GAS COMPANY, COMPLAINANT v. MISSISSIPPI RIVER FUEL CORPORATION, DEFENDANT, DOCKET NO. G–17832

ORDER MODIFYING OPINION AND ORDER, DENYING REHEARING, AND DENYING MOTIONS

(Issued June 15, 1962)

The Granite City Group of Interveners,[1] Owens Illinois Glass Company, Laclede Gas Company, Mississouri Natural Gas Company, and Arkansas-Louisiana Gas Company, as successor to MidSouth Gas Company (Ark-La, MidSouth), have filed applications for rehearing of the Commission's Opinion and Order No. 355, issued April 18, 1962, 27 FPC 697. Both Owens Illinois and the Granite City Interveners have requested stay of our order. Missouri Natural and Laclede have responded to the Granite City motion for a stay. Mississippi River Fuel Corporation has filed a motion to file an answer to the applications for rehearing and motions to stay, and on May 17, 1962, has filed certain tariff sheets in purported compliance with our order.

In our opinion and order we found that Mississippi had capacity to deliver natural gas in excess of that available to its firm utility customers. We found that this excess capacity was being used in part to serve the company's direct industrial customers under contracts which we found provided for interruptible service. Because of the needs of the utility customers we allocated an additional portion of Mississippi's capacity to them leaving with the industrial customers 25,000 Mcf per day of Mississippi's firm capacity.

The Granite City Interveners and Owens Illinois contend that we have improperly impaired Mississippi's service to them. We are of the opinion that their principal arguments are answered by the considerations expressed in our Opinion No. 355. However, we note that Owens Illinois contends that in reducing the amount of firm gas available for Mississippi's industrial customers we held that the controlling question is not the service actually rendered, but the type of service which Mississippi is contractually obligated to render. We recognize that the question under Section 7(a) of the Gas Act is one of "service", but what we endeavored to explain was that the concept of "service" in this connection includes the obligation and whether such service is "firm" or "interruptible" necessarily depends on the contract terms. *Sunray Mid-Continent Oil Co.* v. *F.P.C.*, 264 U.S. 137, cited by Owens Illinois involved a different question, *i.e.*, whether "service" under section 7(e) which an applicant for a certificate was willing to perform was limited by a contractural term of 20 years.

Owens Illinois contends further that the end result of the order accompanying Opinion No. 355 insofar as it increases the stated or contract demands of Mississippi's utility customers simply means that the utility customers receive additional gas which may be diverted to any use, that is, residential, commercial or even additional industrial sales, and that there will be an impairment of service to the industrial customers of the utilities in the St. Louis area. In our opinion and order we allocated available supplies first to the domestic and

[1] Granite City Steel Company, American Steel Foundries, Inc., American Zinc Company of Illinois, The Dow Metal Products Company, Laclede Steel Company, Olin Mathieson Chemical Corporation, National Lead Company, Pittsburgh Plate Glass Company, C. K. Williams & Company.

commercial customers of the utility customers of Mississippi. The remaining firm gas we allocated to the industrial customers of Mississippi and of the utilities on the basis of their requirements. As it happened the industrial customers of Mississippi, requiring 61,202 Mcf per day, received an allocation of 24,608 Mcf per day[2] while the utility customers requiring 64,017 Mcf per day for industrial service received 25,740 Mcf for this purpose, 40.2 percent of requirements in each case. The record shows the industrial and non-industrial requirements of Mississippi and its customers, and we have allocated the gas on that basis.

In connection with the availability of gas to Mississippi, we may note, as did Owens Illinois, that Mississippi and its subsidiary, Mississippi River Transmission Corporation, have filed an application on May 15, 1962, in Docket No. CP61-341 by which Transmission proposes to sell 35,630 Mcf of gas per day to be purchased from Natural Gas Pipeline Company of America. It appears from the application that a large part of this gas will be available for delivery to Mississippi's industrial customers. While we do not intend to prejudge this proceeding, it supports our statement in the opinion concerning the possibility of additional gas from Transmission.

Missouri Natural Gas Company, Laclede Gas Company, and Ark-La (Mid-South) contend that the increases in demands for gas applicable to them should not become effective prior to December 1, 1962. These three customers of Mississippi argue that they are not able to use the gas before that date but nevertheless will be required to pay a demand charge. The question here is how to treat the summer months of 1962 with respect to the new service to the utility customers. Of course, in 1963 and succeeding years the utility customers will be required to pay a demand charge for the new gas even in those months when they are unable to take their full allocation. In the first year, however, it would not seem equitable to place the entire burden of this additional capacity made available by our opinion on the utility customers before the height of the heating season. On the other hand Mississippi is required to hold this additional capacity available and cannot dispose of it on a firm basis but can dispose of it on an interruptible basis to industrial customers. We think that an equitable solution would be to require that the increased demands of the utility customers be made effective October 1, 1962. Beginning with that month the space heating load of the utility customers would become a significant factor although the peak would not be reached until later in the season.

In the motion filed May 16, 1962, the Granite City Interveners requested stay of our order until further authorization or until the order has been approved by an appropriate court. The request for a stay made by Owens Illinois in its application for rehearing was similar. Missouri Natural and Laclede have opposed the Granite City motion citing the need of their customers for the gas, which the Commission's order allocated to them. The stay requested would result in irreparable injury to Mississippi's utility customers who are the victims of the existing unlawful allocation. The stay is therefore denied.

Mississippi's combined motion for authority to file an answer to the applications for rehearing and motions for stay is not proper and must be denied, for there is no provision in our rules for such a filing.

The Commission further finds:

(1) The assignments of error and grounds for rehearing set forth in the applications for rehearing of the Granite City Interveners and Owens Illinois

[2] Rounded off to 25,000 Mcf per day for the purposes of the Tariff.

present no facts or principles of law which were not considered by the Commission when it issued its Opinion No. 355, or which having now been considered warrant any change or modification of the said opinion except as specified below.

(2) The requests for stay filed by the Granite City Interveners and Owens Illinios should be denied.

(3) The motion of Mississippi to file an answer to applications for rehearing and requests for stay should be denied.

(4) The requests of Missouri Natural, Laclede and Ark-La (MidSouth) for an effective date of December 1, 1962 with respect to increases in demands should be denied, but the date should be October 1, 1962.

The Commission orders:

(A) The applications for rehearing filed in the above-entitled proceedings by the Granite City Interveners and Owens Illinois are hereby denied except as specified below.

(B) Paragraph (E) of our order of April 18, 1962 is hereby amended to read as follows: "Mississippi shall file new or superseding service agreements to be effective October 1, 1962 containing the contract demands stated in paragraph (B) above."

(C) In serving its direct industrial customers Mississippi shall give priority to requirements for pilot lights, space heating and the prevention of physical damage and its service shall be non-discriminatory with respect to the customers served.

(D) The definition of Firm Industrial Service appended to Section 7.2 of the tariff changes required to be filed by paragraph (C) of our order shall be amended as specified in the text of this order.

(E) The requests for stay filed by the Granite City Interveners and Owens Illinois are hereby denied.

(F) The motion of Mississippi to file an answer to applications for rehearing and requests for stay is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

CITIES SERVICE GAS COMPANY, DOCKET NO. CP62-211

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 15, 1962)

On March 12, 1962, Cities Service Gas Company (Applicant) filed in Docket No. CP62-211 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the sale of natural gas and the construction and operation of facilities therefor, in Rice County, Kansas, all as more fully set forth in the application.

Applicant proposes to sell and deliver natural gas to The Gas Service Company (Gas Service) for resale in and about the City of Raymond, Kansas. Gas Service proposes to construct and operate a natural gas distribution system in the City of Raymond for which it has received a Certificate of Convenience and Authority from the Kansas State Corporation Commission and a franchise

from the City of Raymond. Gas Service estimates the natural gas requirements for the proposed distribution system to be as follows:

Year	Mcf at 14.73 psia	
	Peak day	Annual
1	76	7,200
2	95	9,000
3	114	10,800

Applicant proposes to construct and operates a meter and appurtenant regulator facilities to make the subject sale at an estimated cost of $1,610, which will be financed from treasury cash. The sale will be made under Applicant's FPC Gas Tariff on file with the Commission.

Pursuant to due notice, a public hearing was held in Washington, D. C., on June 7, 1962, respecting the matters involved in and the issues presented by the application herein. No protest or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Cities Service Gas Company, a Delaware corporation having its principal place of business in Oklahoma City, Oklahoma, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of December 28, 1943, in Docket No. G–298 (4 FPC 471).

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce subject to the jurisdiction of the Commission, and the construction and operation thereof and the transportation and sale of natural gas by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The construction and operation of the proposed facilities and the proposed sale of natural gas by Applicant are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations, and that the construction of the facilities authorized by this order should be completed and said facilities placed in actual operation and the proposed sale hereinafter authorized should commence within 1 year from the date on which this order issues.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Cites Service Gas Company, to construct and operate the proposed facilities and to sell and deliver natural gas as hereinbefore described, all as more fully described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c)(3), (c)(4) and (e) of Section 157.20 of such Regulations.

(C) The facilities hereby authorized shall be constructed and placed in actual operation and the sale and delivery of natural gas shall commence, as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act, within 1 year from the date on which this order issues.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

NATURAL GAS PIPELINE COMPANY OF AMERICA, DOCKET NO. CP62-174

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 15, 1962)

On January 25, 1962, as supplemented on March 5, 1962, Natural Gas Pipeline Company of America (Applicant) filed in Docket No. CP62-174 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of a side tap and approximately 13.6 miles of 10-inch lateral pipeline replacing an equivalent length of 4-inch pipe on the DeKalb-Sycamore lateral in DeKalb Count, Illinois.

The lateral being replaced is part of 16 miles of 4-inch lateral pipeline extending from Applicant's 20-inch pipeline in Illinois to a point of connection with the facilities of Northern Illinois Gas Company (Northern), serving the communities of DeKalb and Sycamore, Illinois. The purpose of this replacement is to increase the capacity of pipelines serving these communities in order to meet expected increased requirements.

Applicant states that the described facilities have been constructed and were placed in operation October 17, 1961. Applicant states further that it is seeking authorization herein because of Commission order No. 241 issued January 12, 1962, in Docket No. R-205, 27 FPC 33, amending Section 2.55 of the Commission's Rules of Practice and Procedure.

The actual cost of construction is $349,415, which cost is being financed from funds on hand.

Applicant does not propose herein any change in its presently authorized daily contract quantities for Northern.

Pursuant to due notice, a public hearing was held in Washington, D.C., on June 5, 1962, respecting the matters involved in and the issues presented by the application, as supplemented, herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally

at the hearing that the intermediate decision precedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Natural Gas Pipeline Company of America, a Delaware corporation having its principal place of business in Chicago, Illinois, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of October 13, 1942, in Docket No. G–235 (3 FPC 830).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, are to be used in the transportation and sale of natural gas in interstate commerce, subject to the jurisdiction of the Commission and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the described facilities by Applicant are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

(6) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Natural Gas Pipeline Company of America, to construct and operate the described facilities in order to sell and deliver natural gas to Northern, as hereinbefore described, all as more fully described in the application, as supplemented, herein, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a) and (e) of Section 157.20 of such Regulations.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

PUGET SOUND POWER & LIGHT COMPANY, PROJECT NO. 2150

ORDER APPROVING PROJECT EXHIBITS AND PRESCRIBING ADDITIONAL ANNUAL CHARGES

(Issued June 15, 1962)

On December 29, 1958, October 5 and October 19, 1960, Puget Sound Power & Light Company, licensee for major Project No. 2150, filed for Commission

approval Exhibits J, K, L and M for the Upper and Lower Baker River developments both of which are included under the license for the project. The licensee also requests that since the license includes both the Upper and Lower Baker River Developments, the license be amended to designate the entire project as the Baker River Project rather than as Upper Baker River Development as at present.

The project affects navigable waters of the United States and lands of the United States within the Mt. Baker National Forest.

The license for the project when issued, effective May 1, 1956, covered the then proposed Upper Baker River Development and the then constructed Lower Baker River Development, except for the United States lands occupied by the Lower development which were under license for minor-part Project No. 777 and lands of the United States occupied by the Upper development, which had not at that time been determined and described. Amendment No. 2 of the license, issued July 7, 1960, included thereunder the United States lands occupied by the Lower Baker Development, fixed the annual charges for such occupancy ($151.00, effective June 1, 1960), reserved the right to determine land charges for the Upper Baker Development when the extent of such lands had been determined, and accepted surrender of the license for minor-part Project No. 777.

The afore-mentioned exhibits show and describe the "as built" project facilities of both the Upper and Lower Baker Developments and the project area and boundary. Thus, approval of the exhibits will show as included in the license: (a) an earth-fill embankment to collect seepage flows from surface strata west of the West Pass Dike Area which are returned to the Upper Baker Development; (b) fish handling facilities to pass downstream migrant fingerlings; (c) 3,764.63[1] acres of lands of the United States occupied by the Upper Baker Development for annual charge purposes; (d) annual charges hereinafter fixed for such occupancy by the Upper Baker Development; (e) the West Pass auxiliary earth fill dike and two 700 horsepower electric motor pumps at the Upper Baker Development; and (f) the description of the license of the Upper Baker-Lower Baker 110 kv transmission line (not on lands of the United States) which was inadvertently omitted from the project description.

We are herein for the first time describing and including in the license the lands of the United States occupied by the Upper Baker Development and prescribing annual charges for such occupancy, effective from May 1, 1956, the effective date of the license, to June 1, 1960, in a specified annual amount, and thereafter in a specified increased annual amount for both the Upper and Lower Baker Developments.

The Department of the Army, Corps of Engineers, has reported that the plans of the structures affecting navigation are satisfactory and are approved and no additional terms and conditions in the interest of navigation are deemed necessary.

The Chief, Forest Service, acting for the Secretary of Agriculture, who has supervision over the Mt. Baker National Forest, has reported that the proposed project area as defined in Exhibits J and K will not interfere or be inconsistent with the purpose for which the Mt. Baker National Forest was created or acquired.

[1] This total includes 20.00 acres of United States lands of Schaddlers Island which should be included in the license, but does not include approximately 388.60 acres of lands conveyed to the United States under Forest Exchange Act of March 20, 1922 (42 Stat. 465) as amended February 28, 1925 (43 Stat. 1090), subject to perpetual (unlimited) flowage rights to the licensee and consequently not subject to annual charges under the Federal Power Act.

An Assistant Secretary of the Interior has reported that the layouts for the general fish facilities shown on Exhibits K and L are satisfactory with the understanding that some minor alterations may be made as shown to be necessary from study of continued operation of the facilities.

The Commission finds:

(1) The following described exhibits conform to the Commission's rules and regulations and should be approved as part of the license for the project, and the exhibits described herein as being superseded and which are now part of the license should be eliminated therefrom:

Exhibits J (FPC No. 2150-3) Revised August 1, 1960, superseding Exhibit J (FPC No. 2150-3); J. (FPC No. 2150-50) superseding J (FPC No. 2150-6); K–1 (FPC No. 2150-53); K–1A (FPC No. 2150-54); K-2 (FPC No. 2150-9) Revised August 1, 1960; K–3 (FPC No. 2150-10) Revised August 1, 1960; K–4 (FPC No. 2150-11) Revised August 1, 1960; K–1 (FPC No. 2150-26) Revised August 1, 1960; K–2 (FPC No. 2150-27) Revised August 1, 1960; K–3 (FPC No. 2150-55); J & K (FPC No. 2150-52); and J–2 of 2 (FPC No. 2150-51) which needs no approval since it is identical with J (FPC No. 2150-7) now part of the license; and

Exhibits L, Sheet 1 (FPC No. 2150-56) superseding L, Sheet 1 (FPC No. 2150-28); L, Sheet 2 (FPC No. 2150-57) superseding L, Sheet 2 (FPC No. 2150-5); L, Sheet 3 (FPC No. 2150-58) superseding L, Sheet 3 (FPC No. 2150-29); and

Exhibit M, (revised 9/1/60) supersedeing Exhibit M filed October 14, 1955.

(2) The amount of annual charges to be paid under the license for the purpose of recompensing the United States for the use, occupancy and enjoyment of its lands within the Mt. Baker National Forest by the Upper Baker Development is reasonable as hereinafter fixed and specified.

The Commission orders:

(A) The exhibits described in finding (1) above as conforming to the Commission's rules and regulations are approved as part of the license for Project No. 2150, and the exhibits described in the same finding as being superseded are eliminated from the license for the project.

(B) Finding paragraphs (4)(a) and (b) of the license for the project are modified to read as follows:

(4) The project hereinafter authorized, to be known as the Baker River Project, consists of:

(a) All lands constituting the project area and enclosed by the project boundary or the limits of which are otherwise defined, and/or interest in such lands necessary or appropriate for the purposes of the project, whether such lands or interest therein owned or held by the Applicant or by the United States; the general location of such project area and project boundary being shown and described by certain exhibits which formed part of the application for license or for amendment thereof and which are designated and described as follows:

Exhibit J: Revised (FPC No. 2150-3) General Map of Upper Baker River Development;

Exhibit J: (FPC No. 2150-50) General Map of Lower Baker River Development;

Exhibit J: (FPC No. 2150-7) General Map of Transmission Line;

Exhibit J & K: (FPC No. 2150-52) Map of Transmission Line Upper Baker River Development;

Exhibit K: (Supplementary) (FPC No. 2150 30 through -38) Detail Map of Transmission Line;

Exhibit K: (Supplementary) Sheet 5 (FPC No. 2150-49) Detail Map for Lower Baker River Development;

Exhibit K-1: (FPC No. 2150-53) Detail map of Project Area Lower Baker River Development;

Exhibit K-1A: (FPC No. 2150-54) Detail Map of Project Area Lower Baker River Development;

Exhibit K-2: (FPC No. 2150-9) Detail Map of Project Area Lower Baker River Development;

Exhibit K-3: (FPC No. 2150-10) Detail Map of Project Area Lower Baker River Development;

Exhibit K-4: (FPC No. 2150-11) Detail Map of Project Area Lower Baker River Development;

Exhibit K-1: (FPC No. 2150-26) Detail Map of Project Area Upper Baker River Development;

Exhibit K-2: (FPC No. 2150-27) Detail Map of Project Area Upper Baker River Development;

Exhibit K-3: (FPC No. 2150-55) Detail Map of Project Area Upper Baker River Development.

(b) Principal structures comprising—

(1) *The Lower Baker River development*, consisting of: (existing project works) a concrete gravity-arch dam having a spillway section surmounted by gates and splashboards and non-overflow sections at each end of the dam, creating a reservoir (Lake Shannon) with surface at elevation 438.52 feet (U.S.G.S.) and extending upstream about 7½ miles to the tailwater of the proposed Upper Baker River development; intake structure; pressure tunnel; surge chamber; penstocks; powerhouse containing two 27,000-horsepower turbines each connected to a generator rated at 21,950 kilovolt-amperes at 90 percent power factor; step-up transformers; two 110-kilovolt transmission lines connecting the transformers with the Applicant's existing Sedro-Woolley Substation; and appurtenant facilities; and (proposed project works) an extension of the pressure tunnel; surge tank; penstock; and extension of the existing powerhouse to contain a single 80,000-horsepower turbine connected to a generator rated at 64,000 kilovolt-amperes at 90 percent power factor; step-up transformer; fish handling, collection and passage facilities; and appurtenant facilities; and

(2) *The Upper Baker River development*, consisting of a concrete gravity dam located a short distance above the head of Lake Shannon reservoir, having a gated spillway section and a 12 foot roadway atop the dam, creating a reservoir about 9 miles long with highwater surface at about elevation 724 feet (U.S.G.S.); an earth and rock-fill dike at West Pass; an auxiliary earth-fill dike; two 700 horsepower electric motor pumps; powerhouse at the downstream toe of the dam containing two turbines each rated at about 60,000 horsepower at a net head of 275 feet and driving a 42,500 kilowatt generator; two penstocks; a step-up transformer; a 110 KV transmission line from Upper Baker substation to Lower Baker substation; fish handling, collection, passage and spawning facilities; and appurtenant electrical and mechanical facilities; the location, nature and character of which are more specifically shown and described by the exhibits hereinbefore cited and by certain other exhibits which also formed part of the application for license or for amendment thereof and which are designated and described as follows:

Exhibit L: (Supplementary) (FPC No. 2150-22) Showing general plan and profile of Lower Baker River development; (FPC No. 2150-39) showing plan and details of dam of the Lower Baker River development; (FPC No. 2150-40) Showing floor plan of powerhouse of Lower Baker River development; (FPC

No. 2150-41) showing cross sections of powerhouse of Lower Baker River development;

Exhibit L-1: (FPC No. 2150-56) Plans and Sections, Upper Baker River development;

Exhibit L-2: (FPC No. 2150-57) Plans and Sections, Upper Baker River development;

Exhibit L-3: (FPC No. 2150-58) Dike Plan and Sections, Upper Baker River development;

Fish Handling Facilities

Exhibit L: (Supplementary) Sheet 5 (FPC No. 2150-42) General Plan, Barrier Dam and Fish Trap; Sheet 6 (FPC No. 2150-43) Fish Trap and East Abutment, Plan and Sections; Sheet 7 (FPC No. 2150-44) Barrier Dam and Apron, Plan and Details; Sheet 8 (FPC No. 2150-45) Key Plan Fish Handling Equipment; Sheet 9 (FPC No. 2150-46) Longitudinal Section through Fish Trap; Sheet 10 (FPC No. 2150-47) West Abutment Wall and Miscellaneous Details; and Sheet 11 (FPC No. 2150-48) General Arrangement of Radial Gates.

Exhibit M: (Supplementary) Statement in ten sheets—General Description and Specifications of Equipment of the Lower Baker River Development (filed October 17, 1957); and

Exhibit M: (Revised September 1, 1960): General Description and Specifications of Equipment at Upper Baker River Development, comprising eight typewritten pages (filed October 5, 1960).

(C) Subparagraph (ii) of Article 40 of the license, as amended, is modified, effective as of May 1, 1956, to read as follows:

(ii) For the purpose of recompensing the United States for the use, occupancy, and enjoyment of its lands, $7,529.26 to June 1, 1960, and $7,680.26, thereafter.

(D) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313 (a) of the Federal Power Act and failure to file such an application shall constitute acceptance of this order. In the acknowledgment of the acceptance of this order, it shall be signed for the Licensee and returned to the Commission within 60 days from the date of its issuance.

LETTER REJECTING PROPOSED RATE SCHEDULE SUPPLEMENT AND RELATED PETITION TO AMEND CERTIFICATE ORDER

Docket No. G–15431

THE SUPERIOR OIL COMPANY

JUNE 15, 1962.*

THE SUPERIOR OIL COMPANY,
909 R.C.A. Building,
1725 K Street, N.W., Washington 6, D.C.
Attention: Mr. H. J. Penn.

GENTLEMEN: This is with reference to your letter of May 25, 1962, submitting (1) a supplemental agreement dated April 9, 1962, dedicating additional acreage, for filing as a proposed supplement to your FPC Gas Rate Schedule No. 77 and (2) a related petition to amend the order granting certificate in Docket No. G–15431 to include thereunder the additional acreage.

The additional sale is proposed to be made pursuant to a supplemental agreement dated April 9, 1962, which, in effect, incorporates by reference the terms

*Affirmed, 322 F. 2d 601 (CA9–1963) cert. den. 377, U.S. 922 (1964).

of a contract dated June 11, 1958. The supplemental agreement appears, therefore, to incorporate by reference pricing provisions other than those permitted by Section 154.93 of the Commission's Regulations. Therefore, in accordance with Commission Order No. 242 (copy enclosed), and Section 154.100 of the Commission's Regulations, the proposed rate schedule supplement and related petition to amend are hereby rejected. All available copies are returned herewith.

This rejection is without prejudice to the resubmittal of the subject filings upon deletion of the unacceptable provisions.

Very truly yours,

J. H. GUTRIDE,
Secretary.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TIDEWATER OIL COMPANY, ET AL., DOCKET NO. G-13310, ET AL.[1]

ORDER CONDITIONALLY APPROVING GENERAL RATE SETTLEMENT PROPOSAL, SEVERING PROCEEDINGS, TERMINATING PROCEEDINGS AND REQUIRING REFUNDS

(Issued June 15, 1962)*

Syllabus

1. Commission conditionally *approves* rate settlement proposal; deems Examiner's decision moot; and terminates proceedings initiated under Sections 4(e) and 5(a) of the Natural Gas Act. P. 1270.

Robert E. Morse, Jr., J. Evans Attwell, Gene M. Woodfin, and *Robert Koch* for Tidewater Oil Company.

J. Harry Mulhern, Edward S. Kirby, and *William R. Duff* for Public Service Electric and Gas Company.

Vincent P. McDevitt, Samuel G. Miller, H. P. Sullivan, and *Ray Schroeder* for Philadelphia Electric Company.

William A. Dougherty, C. W. Cooper, George C. Williams, Norman A. Flaningam, Ray O. Martin, G. Kirby Harrington, James B. Sayers, and *Denton Borger* for Consolidated Natural Gas System.

J. David Mann, Jr., Thomas B. K. Ringe, and *Thomas Bracken* for United Gas Improvement Company.

Eugene J. Bradley for Philadelphia Electric Company.

Ray Schroeder for Public Service Electric and Gas Company.

John P. Randolph for United Fuel Gas Company.

Luke R. Lamb and *Alan J. Roth* for the Staff of the Federal Power Commission.

On March 28, 1962, Tidewater Oil Company (Tidewater) filed a petition requesting that the Commission issue an order approving a settlement proposal concerning the rates under 70 of its rate schedules[2] plus 55 related suspension

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* Initial decision appears on page 1276. Modified by order issued July 11, 1962, 28 FPC 108.

[1] The other docket numbers are listed in Column 6 of Exhibit I. Some of the proceedings presently are consolidated with Docket Nos. AR61-2, *et al.*, and will be severed therefrom.

[2] Most of Tidewater's other rate schedules, not subject to the settlement proposal, will be subject to determinations in Docket Nos. AR61-1, *et al.*, should be terminated due to depletion of gas reserves, are in litigation, or are involved in pending certificate proceedings.

proceedings, three certificate proceedings, and a general rate investigation proceeding. The settlement proposal (attached hereto as Appendix A) was executed by Tidewater, Public Service Electric and Gas Company, The United Gas Improvement Company, The East Ohio Gas Company, Hope Natural Gas Company, New York State Natural Gas Corporation, The Peoples Natural Gas Company, and Lake Shore Pipe Line Company. All these parties also join in the petition for approval of the settlement proposal. No one has filed objections to the settlement proposal. The Public Service Commission of the State of New York filed preliminary comments to the proposal and a request for additional information. Philadelphia Electric Company and Texas Gas Transmission Corporation have also filed comments to the settlement proposal.

The settlement proposal provides for (1) rates generally at or below applicable area ceilings, (2) a two-year moratorium on rate increases above ceiling, (3) a post-moratorium limit on rate increases to one cent every four years, (4) waiver of the right to file for rate increases under indefinite pricing provisions in twelve rate schedules and (5) refunds based upon the difference between rates in effect subject to refund and the related settlement rates. Tidewater submits the proposal on condition that the proceeding in Docket No. G–13310 and the proceedings listed in Exhibit I hereto be terminated.

In support of the proposal, Tidewater states that the settlement provides for long-term price stability at rates generally conforming to established area rate standards, that the conclusion of the proceedings will release funds for exploratory and developmental activities and will relieve all parties of the costly and time-consuming effort of further pursuing the proceedings, and that the number of Tidewater's future filings for rate increases will be reduced by the moratorium on filings, by the post-moratorium limit on increases, and by the waiver of rights to file for indefinite price increases under twelve rate schedules.

One settlement rate which exceeds the ceiling is the proposed increased rate of 17.5¢ plus 1.75¢ tax reimbursement for a substantial sale of gas to United Gas Pipe Line Company (United Gas) from Hollywood Field, South Louisiana. The ceiling for increased rates in the area is 14.0¢ plus tax reimbursement (15.75¢ for this sale). In support of the proposed rate, Tidewater states as follows: During the course of drilling the discovery well in 1953, extremely high pressures were encountered and a dangerous blow-out and fire resulted. Although the well was later brought under control, it could not be shut in because of the pressures; an emergency sale was necessary to the only pipeline in the vicinity that had the capacity to take the some 35,000 Mcf per day that was being vented. A three-year contract was negotiated at a distress rate of 9.0¢ per Mcf plus 1.0¢ tax reimbursement. Shortly thereafter, on December 21, 1955, a renegotiated contract was executed providing for a rate of 18.5¢ plus tax reimbursement. The Commission suspended Tidewater's filing for the increased rate in Docket No. G–9932 and it became effective subject to refund on June 3, 1956. Under nearly identical circumstances the Commission has previously approved the settlement of a proceeding at the same rate of 19.25¢ per Mcf for a sale from acreage adjacent to Hollywood Field. *John W. Mecom*, 25 FPC 1022. We there noted that the increased rate was in the nature of an initial rate and was, at the proposed settlement level, compatible with the initial rate ceiling. We likewise approve Tidewater's proposed settlement rate.

However, Tidewater has proposed certain other rates which are in excess of ceiling and which accordingly should be reduced as follows: (1) The proposed settlement rates under Rate Schedule Nos. 5 and 18 are 15.34592¢ per Mcf (including tax reimbursement) for gas sold from Texas R. R. District No. 3.

That rate reflects a periodic increase from the initial rate and is above the ceiling for increased rates in the area. The rate should be reduced to the initial rate under the contracts of 15.144¢ per Mcf (including tax reimbursement), which is less than the ceiling for initial rates in the area. (2) The proposed settlement rates under Rate Schedule No. 26 are 21¢ per Mcf for reserves originally subject to the contract and 21.4¢ per Mcf for reserves later dedicated to the contract. These settlement rates are the initial rates under the rate schedule for the two classes of reserves. The 21.4¢ rate exceeds the initial rate ceiling of 21.25¢ (inclusive of tax reimbursement) for the area (South Louisiana); the proposed 21.4¢ settlement rate should be reduced to the ceiling level of 21.25¢. (3) The proposed settlement rate under Rate Schedule No. 57 is 14.3¢ per Mcf, after deduction of a 0.5¢ line amortization credit by the purchaser, for gas sold from Texas R. R. District No. 6. The total rate is thus 14.8¢ per Mcf, which exceeds the applicable 14.6¢ ceiling for increased rates under rate schedules from which favored-nation and redetermination price provisions have been eliminated. (Tidewater waives its rights under indefinite pricing provisions in this rate schedule.) The total settlement rate should be reduced to 14.6¢ per Mcf.

We recognize that the proposed settlement rates under Rate Schedule Nos. 5, 18 and 26 were previously accepted by the Commission, without suspension or condition, when originally filed by Tidewater. But we are now asked to approve these rates as part of the settlement proposal, and this we will not do in light of the recently established area rate standards. We shall therefore condition our approval of the settlement proposal to require Tidewater to reduce the rates as stated above.

Tidewater proposes that, on the basis of the settlement, the Commission terminate the certificate proceedings in Docket Nos G–16172, CI60–430, and CI61–171 applicable to Rate Schedule Nos. 75, 100, and 102. Tidewater is currently operating under these rate schedules on unconditioned temporary authorizations granted in the certificate proceedings. We note that the proposed settlement rates for each of these sales is less than the applicable initial rate ceiling level. However, Section 7 of the Natural Gas Act requires a hearing before the grant of permanent certificates, and we therefore cannot dispose of these certificate matters by settlement. We propose instead promptly to set these certificate matters for hearing and will modify the settlement proposal consistent with the foregoing.

On September 14, 1961, the Presiding Examiner issued his initial decision in the Section 5(a) proceeding in Docket No. G–13310 and the consolidated Section 4(e) proceedings in Docket Nos. G–9932, G–9241, G–9551, G–9552, G–9608, G–10998, G–11318, G–11319, G–11340, G–11357, G–11907 and G–12999. Tidewater proposes that all these proceedings (and others) be disposed of under the settlement. In his decision, the Presiding Examiner dismissed the Section 5(a) proceeding, declining to set future rates for Tidewater, and disallowed the rate increases subject to the consolidated 4(e) proceedings upon a finding that company-wide test jurisdictional revenues exceeded costs by more than the rate increases. Philadelphia Electric Company, the Public Service Commission of the State of New York, and certain signatories to the settlement proposal have commented favorably on the Examiner's cost analysis. However, we approve of and want to encourage settlements which dispose of most of a producer's pending rate problems, which do so in accord with our area rate ceilings,[3] which provide for a reasonable moratorium on increased

[3] *Statement of General Policy No. 61–1*, 24 FPC 818, as amended.

rate filings, which require refunds where appropriate, which lend certainty to the purchased gas costs of buyers, and which free the producer's revenues from contingencies that no doubt inhibit exploratory and developmental activities. Tidewater's settlement proposal in general provides all these substantial benefits and thus goes well beyond the Examiner's decision. Without passing on the validity of the Examiner's decision, we find that the public interest will best be served by approving Tidewater's settlement proposal, with certain modifications and conditions. The Examiner's decision accordingly becomes moot.

Our approval of the settlement proposal should not be construed as constituting approval of any future rate increases that may be filed under the subject rate schedules and is without prejudice to any findings or orders of the Commission in any further proceedings, including area rate proceedings, involving Tidewater's rates and rate schedules.

The Commission finds:

(1) The settlement of the proceeding in Docket No. G–13310 and the proceedings listed in Column 6 of Exhibit I hereto—other than Docket Nos. G–16172, CI60–430, and CI61–171—on the basis of the settlement proposal submitted by Tidewater and others, as hereinafter modified, is in the public interest in carrying out the provisions of the Natural Gas Act and should be approved and made effective subject to the terms and conditions ordered.

(2) Rates under the rate schedules subject to the settlement should be disallowed to the extent they exceed the settlement rates as modified.

(3) The proceedings listed in Column 6 of Exhibit I which are now consoli dated with Docket No. AR61–2, *et al.*, should be severed therefrom.

(4) The decision of the Presiding Examiner in Docket No. G–13310, *et al.*, should be deemed to be moot.

The Commission orders:

(A) The settlement of these proceedings on the basis of the settlement proposal attached hereto as Appendix A is approved and made effective subject to the following modifications, terms and conditions.

(B) Tidewater shall substitute, in lieu of the related proposed settlement rates, rates of 15.144¢ per Mcf under its FPC Gas Rate Schedule Nos. 5 and 18; 14.6¢ per Mcf, including 0.5¢ deducted by the purchaser, under its Rate Schedule No. 57; and 21.25¢ for the sale of additional acreage dedicated in Supplement No. 5 under its Rate Schedule No. 26.

(C) The certificate proceedings in Docket Nos. G–16172, CI60–430, and CI61–171 shall not be terminated on the basis of the settlement but shall be determined after hearing. Tidewater shall file an amended application in Docket No. G–16172 in conformity with the proposed settlement rate. Tidewater shall abide by ultimate Commission decision, after judicial review if any, in these certificate proceedings. The involved rates and rate schedules shall otherwise remain subject to the terms of the settlement.

(D) Rates under the rate schedules subject to the settlement are hereby disallowed to the extent they exceed the settlement rates listed in Column 5 as modified according to paragraph B above. Within 45 days from the date of this order Tidewater shall refund with interest as specified in each docket the difference between all charges collected under the subject rate schedule at rates in effect subject to refund and the lesser charges that would have been collected at the related settlement rates as modified according to paragraph B above.

(E) Within 45 days after the date of this order Tidewater (1) shall make such filings under its rate schedules as are required to make effective the terms of settlement proposal, as modified according to paragraph B above, and (2) shall report to the Commission, in writing and under oath, the amount of refund made to each of its purchasers, showing separately the amount of principal and interest so paid and the bases used for such determinations, together with releases from its purchasers showing receipt of the refunds in conformity to the settlement as modified and approved.

(F) Tidewater shall, over the signature of a responsible officer, file with the Commission, within 30 days from the date of issuance of this order, in writing and under oath, an original and one copy of its acceptance or rejection of the terms and conditions of this order.

(G) The rate proceedings in Docket Nos. G–13378, G–13386, G–13436, G–13580, G–16593, G–16594, G–17998, G–17999, G–18751, G–19646, G–19647, G–20011, RI61–124, RI61–125, RI61–159, RI61–292, and RI61–297 and the certificate proceedings in Docket Nos. G–16172, CI60–430, and CI61–171 are hereby severed from the consolidated proceedings in Docket No. AR61–2, *et al.*

(H) Upon full compliance by Tidewater with all the terms and provisions of this order and of the settlement proposal as hereby modified and approved, the proceeding in Docket No. G–13310 and the proceedings listed in Column 6 of Exhibit I—other than Docket Nos. G–16172, CI60–430, and CI61–171—shall terminate, and the Presiding Examiner's decision issued on September 14, 1961, in Docket No. G–13310, *et al.*, shall be deemed to be moot.

(I) This order is without prejudice to any findings or orders which have been or may be made hereafter by the Commission, and is without prejudice to claims or contentions which may be made by the Commission, Tidewater, the Commission staff, or any affected party herein, in any proceedings now pending or hereafter instituted by or against Tidewater or any other companies, persons, or parties affected by this order.

EXHIBIT I

TIDEWATER OIL COMPANY

PROPOSED RATES

TEXAS RAILROAD COMMISSION DISTRICT NO. 2

(Ceilings: Initial—18.0¢; Increases—14.0¢)

(1) Purchaser	(2) Field	(3) FPC gas rate schedule No.	(4) Price as of Mar. 1, 1962 ¢/MCF [1]	(5) Proposed settlement price [1]	(6) Section 4(e) Docket No.	(7) Proposed increase ¢/MCF [2]	(8) Estimated refund to Mar. 1, 1962 excluding interest
Transcontinental Gas P/L Corp	Ike	3	8.875534	8.875534			
Texas Eastern Trans. Corp	Cosden-W	7	[3] 13.8733	[3] 13.8733	G-14687	2.75010	
					RI60-412	[3] 1.07110	0
Transcontinental Gas P/L Corp	Ray-Wilcox	14	8.890883	8.890883			
Transcontinental Gas P/L Corp	West Tuleta	16	8.890883	8.890883			
United Gas P/L Co	Brandt, et al	20	12.1536	12.1536			
Tennessee Gas Trans. Co	Placedo	21	15.33333	14.6	G-17134	4.30515	6,465
United Gas P/L Co	Burnell-N. Pettus	32	9.72288	9.72288			
Texas Eastern Trans. Corp	Nordheim	51	[4] 14.3733	[4] 14.3733	G-14928	2.75010	0
					RI60-411	[3] 1.07110	
Texas Eastern Trans. Corp	West George West	55	[4] 14.3733	[4] 14.3733	RI60-55	2.34562	0
Texas Eastern Trans. Corp	Yoward	63	10.92096	10.92096			
Natural Gas P/L Co	Elms-Shaeffer Ranch	70	14.5	14.5			
United Gas P/L Co	North LaWard	95	14.1792	14.1792			

TEXAS RAILROAD COMMISSION DISTRICT NO. 3

(Ceilings: Initial—18.0¢; Increases—14.0¢)

Iroquois Gas Co	Sheridan	1	17.668	16.6584	G-13387	1.0096	13,202
					RI62-73	1.0096	
Natural Gas P/L Co	East Bay City	5	17.153104	15.34592	G-9241	0.20192	132,139
					G-10998	0.20192	
					G-12999	0.20192	
					G-16080	1.201424	
Tennessee Gas Trans. Co	Sublime	11	15.95016	14.6	G-17135	2.67196	61,121

Tennessee Gas Trans. Co	East Bernard	12	15.95016	14.6	G-17134	2.67196	11,520
Tennessee Gas Trans. Co	East Bay City	13	16.16947	14.6	G-17076	2.67196	156,545
Natural Gas P/L Co	West Bernard	18	17.153104	15.34592	G-9241	0.20192	194,794
					G-10998	0.20192	
					G-12999	0.20192	
					G-16080	1.201424	
Transcontinental Gas P/L Corp	West Bernard	19	9.335428	9.335428			
Natural Gas P/L Co	Old Ocean	22	11.48836	11.48836			
Shell Oil Company	Englehart	49	[4] Cancelled	13.45435	G-11340	0.20315	0
Tennessee Gas Trans. Co	West Rock Island	53	15.95016	14.6	G-17134	2.67196	20,695
Coastal Trans. Corp	Palacios	86	17.5	16.0			
Coastal Trans. Corp	Palacios	88	17.5	16.0			
Trunkline Gas Co	Chocolate Bayou	93	20.0	18.0			

TEXAS RAILROAD COMMISSION DISTRICT NO. 4

(Ceilings: Initial 18.0¢; Increases 14.0¢)

Natural Gas P/L Co	LaGloria	6	9.99886	9.99886			
Tennessee Gas Trans. Co	Mustang Island	9	17.24347	14.6	G-19665	3.13919	76,113
					RI60-396	1.98160	
Transcontinental Gas P/L Corp	LaGloria	15	8.890883	8.890883			
United Gas P/L Co	Red Fish Bay	23	14.8	14.6	G-13513	2.140	9,248
Texas Eastern Trans. Corp	Midway	64	15.0	14.6	G-13488	0.2	571
					G-16627	0.2	
					G-19647	0.2	
					RI61-124	0.2	
					RI62-73	0.2	
Natural Gas P/L Co	Sinton	84	14.5	14.5			

TEXAS RAILROAD COMMISSION DISTRICT NO. 6

(Ceilings: Initial 15.0¢; Increases 14.0¢)

Arkansas Louisiana Gas Co	North Lansing	8	12.55406	12.55406			
Texas Eastern Trans. Corp	Willow Springs	57	[6] 14.5	[6] 14.3	G-13402	0.8984	1,199
					G-16626	0.2	
					G-19646	0.2	
					RI61-125	0.2	
					RI62-109	0.2	
Texas Eastern Trans. Corp	Chalk Hill	87	15.0	14.6	G-19665	0.2	194
					RI61-124	0.2	
					RI62-110	0.2	

See footnotes at end of table.

TIDEWATER OIL COMPANY—Continued

TEXAS RAILROAD COMMISSION DISTRICT NO. 8

(Ceilings: Initial 16.0¢; Increases 11.0¢)

(1) Purchaser	(2) Field	(3) FPC gas rate schedule No.	(4) Price as of Mar. 1, 1962 ¢/MCF [1]	(5) Proposed settlement price [1]	(6) Section 4(e) Docket No.	(7) Proposed increase ¢/MCF [2]	(8) Estimated refund to Mar. 1, 1962 excluding interest
Northern Natural Gas Co.	Emperor	67	16.0	16.0			
West Texas Gathering Co.	Emperor	79	16.0	16.0			
LOUISIANA							
North Louisiana							
Arkansas Louisiana Gas Co.	Rodessa	52	3.0	3.0			
SOUTH LOUISIANA							
(Ceilings: Initial 21.25¢ including tax reimbursement; Increases 14.0¢ plus tax reimbursement)							
United Fuel Gas Co.	North Bourg	24	19.9	17.0	G-9551 G-11357 G-13386 G-16593 G-19647 RI61-124 RI62-149	0.4 0.4 0.4 0.4 0.4 0.4 0.4	34,528
United Fuel Gas Co.	Florence	25	19.9	17.0	G-9552 G-11318 G-13378 G-16594 G-19646 RI61-159 RI62-109	0.4 0.4 0.4 0.4 0.4 0.4 0.4	142,364
United Fuel Gas Co.	Erath unit	26	22.881	21.0	B-9608 G-11319	0.2 0.2	
United Fuel Gas Co.	North Erath & Erath Unit	26	22.881	21.4	G-13580 G-16593 G-20011	0.2 0.2 0.581	294,282
United Gas P/L Co.	Hollywood	34	22.25	19.25	G-9932 RI61-297	9.5 2.0	1,476,894
Texas Gas Trans. Corp.	South Lewisburg	37	21.061	18.75	G-11907	9.2803	179,502
Transcontinental Gas P/L Corp.	LeLeux	54	23.55	17.0	G-17998	8.5	28,970
	Savoy	60	19.9	17.8	G-13436 G-16594	0.4 0.4	10,308

United Fuel Gas Co	Savoy	60	19.9	17.8	G-13436	0.4		10,308
					G-16594	0.4		
					G-19646	0.4		
					RI61-125	0.4		
					RI62-149	0.4		
American Louisiana P/L Co	North Holly Beach	61	19.5	19.0				
Transcontinental Gas P/L Corp	Northwest Gueydan	62	23.55	17.0	G-17999	5.5		70,989
Southern Natural Gas Co	Manila Village	65	19.75	19.0				
United Gas P/L Co	Southeast Houma	66	22.25	20.0	RI61-292	2.0		12,099
United Gas P/L Co	Midland	71	22.25	20.0	RI61-292	2.0		5,580
United Gas P/L Co	Ridge	75	22.25	20.0	G-16172	Certificate	Application	
Southern Natural Gas Co	Bayou Bouillon	81	23.25	20.0				
American Louisiana P/L Co	North Holly Beach	82	19.5	19.0				
Transcontinental Gas P/L Corp	S. E. Rayne	85	[7] Cancelled	[8] 18.05	G-18751	5.5		557
Southern Natural Gas Co	Felice Bayou	99	20.75	20.0				
Tennessee Gas Trans. Co	Caillou Island	100	18.5	18.5	CI60-430	Certificate	Application	
American Louisiana P/L Co	Lacassine Refuge	102	19.75	19.75	RI62-357	[3] 2.5		0
					CI61-171	Certificate	Application	

MISSISSIPPI

(Ceilings: Initial 17.0¢; Increases 14.0¢ including tax reimbursement)

United Gas P/L Co	Baxterville	36	22.88298	14.0	G-18567	10.90428	52,383
Southern Natural Gas Co	Gwinville	68	20.0	14.0	G-14108	12.63529	529,212

NEW MEXICO

(Permian Basin Area Ceilings: Initial 16.0¢; Increases 11.0¢)

El Paso Natural Gas Co	Justis	42	9.0	9.0			
Northern Natural Gas Co	Eumont	76	10.5	10.5			
El Paso Natural Gas Co	Langlie-Mattix	83	9.0	9.0			

OKLAHOMA

(Ceilings: Initial 17.0¢, Panhandle; 16.8¢ Carter Knox; 15.0¢, Other; Increases 11.0¢)

Cities Service Gas Co	West Edmond	40	10.5	10.5			
Lone Star Gas Co	Sholem Alechem	45	11.0	11.0			
Arkansas Louisiana Gas Co	Chickasha	46	11.0	11.0	RI62-170	[3] 4.0	0
Panhandle Eastern P/L Co	South Forgan	73	16.0	16.0			
Wunderlich Development Co	SW Ponca City	78	6.2	6.2			
Colorado Interstate Gas Co	Mocane	96	15.0	15.0			
Transwestern P/L Co	South Goodwin, et al	97	17.0	17.0			
Cities Service Gas Co	SE Woodward	98	[9] 15.0	[9] 15.0			
Arkansas Louisiana Gas Co	E. Kremlin	101	11.0	11.0			

[1] Louisiana and Mississippi prices are at a pressure base of 15.025 PSIA, all other prices are at 14.65 PSIA.
[2] An additional 0.5¢/MCF is received for gathering and dehydration on the Richter Unit.
[3] Increase has not been effective subject to refund.
[4] Includes 0.5¢/MCF for gathering and dehydration.
[5] 13.45435¢/MCF when well P & A.
[6] After deduction of 0.5¢/MCF line amortization charge.
[7] 23.55 when well P & A.
[8] Effective until deliveries ceased on Apr. 5, 1960.
[9] In addition Seller receives 1¢/MCF for gathering & dehydration.

DECISION

UPON A CONSOLIDATED PROCEEDING UNDER SECTIONS 4(e) AND 5(a) OF THE NATURAL GAS ACT TO DETERMINE JUST AND REASONABLE RATES FOR AN INDEPENDENT PRODUCER

(Issued September 14, 1961)

ZWERDLING, *Presiding Examiner:* This consolidated proceeding involves (1) a review under Section 4(e) of the Natural Gas Act concerning the lawfulness of 15 rate increases relating to the sale of gas by Tidewater Oil Company (Tidewater) under eight different contracts from fields in South Louisiana and the Texas Gulf Coast area and (2) an investigation under Section 5(a) of the Act of the rates charged by Tidewater in connection with all of its sales of natural gas subject to the jurisdiction of the Federal Power Commission.

Tidewater is a major, integrated oil company engaged in virtually all phases of the petroleum industry, including the exploration for and the development, production and sale of crude oil and natural gas; the purchase of crude oil from other producers; the refining of crude oil and other petroleum products; the transportation of crude oil and liquid products through company-owned pipelines and tankers; the sale of refined petroleum products at wholesale and retail; the processing of natural gas in gasoline plants; and the exploration for uranium and other operations (Exhibit 144). Operations are conducted throughout the United States and in many foreign countries. Foreign exploration operations are, or have been conducted in Canada, Iran, Turkey, Guatemala, Paraguay and Pakistan (Exhibit 144). At the time these hearings commenced, Tidewater's revenues from gas sales constituted only 2% of total revenues. (1:257)

Tidewater has virtually no dry gas production and in this respect it differs from some other major producers, who produce large quantities of dry gas in relation to their total gas production. The company's principal gas properties are located in the newer gas-condensate producing areas of South Louisiana and the Texas Gulf Coast at depths below 5,000 feet.

Tidewater conducts its domestic exploration and production activities in three divisions: Western, Central and Southern. Its jurisdictional gas sales are made entirely from the Central and Southern divisions—in Kansas, Louisiana, Mississippi, New Mexico,' Oklahoma, Texas, and West Virginia. (Exh. 137) However, 87 percent of its gas reserves are located in its Southern Division. Because the company's jurisdictional gas sales are made entirely from the Central and Southern Divisions, the cost-of-service studies presented by Tidewater and the intervenors in this proceeding have confined solely to those Divisions.

The first stage of this proceeding involved only Docket No. G–9932, relating solely to the Section 4(e) increase in price for gas sold to United Gas Pipe Line Company by Tidewater from the Hollywood Field, Terrebonne Parish, Louisiana—and hearing on this initial phase of the proceeding commenced on May 28, 1956. After several hearing sessions had been held in Docket G–9932, the Commission by order issued September 27, 1957, consolidated that Section 4(e) proceeding with a pending Section 5(a) investigation of all Tidewater's jurisdictional gas rates, and at the same time also consolidated 11 other pending Section 4(e) dockets relating to 14 rate increases.

The proposed Section 4(e) rate increases included in the consolidated proceeding involve the following:

Field Parish or County purchaser	Docket No.	Rate schedule No.	Supplement No.	Date filed	Existing price	Increased price per contract	Amount of increase
					cents	*cents*	*cents*
Hollywood Field, Terrebonne, La., United Gas Pipe Line Co.	G-9932	34	3	Jan. 3, 1956	10.0	19.5	9.5
West Bernard, Wharton, Tex., Texas-Illinois Natural Gas Pipeline Co.	G-9241	18	10	July 22, 1955	15.34692	15.54784	0.20192
	G-10998	18	12	July 30, 1956	15.54784	15.74976	0.20192
	G-12999	18	14	July 15, 1957	15.74976	15.95168	0.20192
East Bay City, Matagorda, Tex., Texas-Illinois Natural Gas Pipeline Co.	G-9241	5	8	July 25, 1955	15.34692	15.54784	0.20192
	G-10998	5	10	July 30, 1956	15.54784	15.74976	0.20192
	G-12999	5	11	July 15, 1957	15.74976	15.95168	0.20192
North Bourg, Terrebonne, La., United Fuel Gas Co.	G-9551	24	5	Aug. 30, 1955	17.0	17.4	0.4
	G-11357	24	6	Oct. 1, 1956	17.4	17.8	0.4
Florence, Vermilion, La., United Fuel Gas Co.	G-9552	25	1	Sept. 30, 1955	17.0	17.4	0.4
	G-11318	25	2	Sept. 27, 1956	17.4	17.8	0.4
Erath, Vermilion, La., United Fuel Gas Co.	G-9608	26	3	Oct. 3, 1955	21.0	21.2	0.2
	G-11319	26	4	Sept. 27, 1956	21.2	21.4	0.2
Englehart, Colorado, Tex., Shell Oil Corp.	G-11340	49	9	Oct. 1, 1956	13.25120	13.45435	0.20315
Lewisburg, Acadia, La., Texas Gas Transmission Co.	G-11907	37	9	Jan. 16, 1957	10.8067	20.186	9.2893

(Tidewater Initial Brief, p. 6)

As in the *Phillips* case (Op. 338), the instant proceeding was presented by all parties on a cost-of-service basis, although Tidewater in addition presented certain evidence relating to trends in industry costs, trends in production, exploration and development, and evidence of current market prices. Evidence was presented by Tidewater, an intervenor group (consisting of Philadelphia Electric Company, Public Service Electric and Gas Company, and The United Gas Improvement Company) and the Commission Staff.[1] In the initial part of the proceeding Tidewater, the intervenors and the Staff presented cost-of-service studies based on the test year 1955. At a subsequent stage of the proceeding in 1959 Tidewater made a new cost-of-service presentation based upon the more recent test year of 1957, and the intervenors thereafter followed with a cost-of-service presentation of their own based upon the 1957 test year. Although the Commission Staff presented its case only upon the basis of the 1955 test year, the Staff briefs rely upon the 1957 data presented by the other parties.

Tidewater presented its 1957 cost studies in Exhibits Nos. 128 and 129 (with illustrative variations in other exhibits). The intervenors presented their 1957 cost-of-service study in Exhibit No. 150, subsequently revised in Exhibit No. 180.

Hearings in the consolidated proceedings concluded on May 23, 1960, and the record includes 7,587 pages of testimony, 180 exhibits, and a number of items by reference. The lengthy period over which the trial of this case was spread resulted from a number of factors, including the following:

(1) A Section 5(a) proceeding was added to the case in midstream.

(2) The landmark *Phillips* producer rate case was being tried throughout the same period, and all parties regarded it as useful to take advantage of the opportunities to learn from and react to the developments in that case.

(3) The resultant time lag since the initial presentation of the case on a 1955 test year basis made it necessary to shift at a late stage of the proceeding to a 1957 test year.

Under all the circumstances, there can be no doubt that the more recent test year of 1957 should be used in fixing Tidewater's rates for the future, and the case will therefore be discussed on that basis.

[1] There were in addition 49 non-active intervenors. Hereafter the term "intervenors" will be used to refer to the participating intervenor group listed above.

Tidewater contends that its cost-of-service for the Southern and Central Divisions based upon the test year 1957 was substantially in excess of its natural gas revenues for that year, and that it therefore suffered a substantial revenue deficiency. On the basis of this conclusion, Tidewater requests that its consolidated Section 4(e) rate increases should be approved and that the pending Section 5(a) investigation should be dismissed. It does not, however, request the Commission to raise its jurisdictional gas revenues above the levels provided in its contracts, in order to equal its claimed cost-of-service. The intervenors and the Staff, on the other hand, constructing a cost-of-service for Tidewater under different methods, both derive a total cost-of-service for Tidewater substantially lower than its jurisdictional revenues for the test year 1957.

THE SIGNIFICANCE OF THE INSTANT CASE

The importance of the instant Tidewater proceeding lies in the fact that it is only the second major producer rate case to reach the point of decision before the Commission since the Supreme Court held in 1954 that the Federal Power Commission has jurisdiction and responsibility to regulate independent producers of natural gas.[2] In the Commission's historic Phillips decision (Op. 338), issued September 28, 1960, 24 FPC 537, it reached and expressed certain general conclusions with respect to the usefulness of the cost-of-service method as applied to producer rate proceedings. Among other things the Commission concluded, on the basis of its experience up to that time, that

> . . . regulation of producers on a company-by-company rate basis method will in all probabilty result in higher consumer prices than we would otherwise have. Since the cost rate base method seems almost always to produce the higher rates it appears that consumers, in most instances, will be thoroughly protected if we place more reliance on existing prices and on applicable economic principles. (Op. 338, p. 546)

This conclusion was based upon the experiences which the Commission had encountered up to that time in a number of minor producer cases, involving relatively small producers, which were tried and decided on an *ad hoc* basis. It was also based upon the fact that in the *Phillips* case itself, employing the cost-of-service methods and techniques there approved, the Commission found that Phillips' total system-wide cost-of-service exceeded the total revenues which it was then collecting under existing contracts, and that Phillips accordingly was suffering a revenue deficiency. This situation resulted, in part, from the fact that Phillips had an unusually large number of old contracts, under which gas was still being delivered under abnormally low prices.

No such circumstances are involved in the instant Tidewater proceeding. The importance of the Tidewater case is that it provides a more solid base for the consideration of these problems than was available to the Commission when it issued its *Phillips* decision. The Commission will therefore undoubtedly desire to weigh and consider the experience, the evidence and the results obtained in the instant Tidewater proceeding, in connection with its continuing effort to exercise its responsibility to resolve the problem of producer rate regulation.

In making this evaluation, the Commission will of course recognize that the price results flowing from the use of a "cost-of-service" method will depend to a major extent upon the techniques which are adopted for the construction of the producer's cost-of-service. If the cost-of-service is constructed under the techniques generally advocated by the producers themselves, it will undoubtedly

[2] *Phillips Petroleum Co. v. Wisconsin*, 347 U. S. 672.

reach an extremely high level and may well exceed field prices. On the other hand, if the cost-of-service is constructed under the methods and techniques approved by the Commission, after careful and extended consideration, in the *Phillips* case, then the experience gained in the instant Tidewater proceeding would appear to demonstrate that the price results will be at a substantially lower level than field prices.

It is important and of interest to recognize at the outset that the major, dollar-impact differences between the types of price levels derived under the cost-of-service techniques advocated by the producers, on the one hand, and those approved by the Commission in *Phillips*, lies mainly in the treatment adopted for a small number of key, basic problems, as follows:

(1) *Allocation of Joint Production Costs Between Liquids and Gas*

Tidewater here advocates the use of the straight Btu method, which results in allocating 25.26 percent of joint production expenses to gas. As will be developed subsequently in this decision, application of the relative cost method approved by the Commission in *Phillips*, as modified in some aspects to reflect operating problems peculair to Tidewater, results in an allocation of 5.98 percent of Tidewater's on-lease production expense to gas.

(2) *Allocation of Exploration Costs Between Liquids and Gas*

Generally, in proceedings pending before the Commission up to this time, producers have advocated the use of the straight Btu method, which results in allocating anywhere from 40 percent to 60 percent of exploration costs to gas. In the instant Tidewater proceeding this method would result in an allocation of 43.07 percent to gas. In *Phillips*, however, the Commission approved a modified Btu method, using an economic adjustment factor of four to reflect relative market prices of liquids and gas—resulting in an allocation of 32.742 percent to gas. In the instant Tidewater proceeding, the use of the modified Btu method, even if modified to reflect an adjustment factor of three (which, of course, would be more favorable to the producer), results in an allocation of 24.17 percent to gas.

(3) *Income Tax Allowance and Rate of Return*

In *Phillips* the producer claimed either actual taxes plus a 17-18 percent rate of return, or in the alternative a rate of return of 12 percent, in addition to the benefits of the statutory tax allowances. In the instant proceeding, Tidewater claims either actual taxes plus a 25 percent return, or in the alternative a 12 percent return plus the benefits of the statutory tax allowances. In *Phillips* the Commission approved a rate of return of 11 percent and allowed only actual tax liability.

In the instant proceeding Tidewater derives a total unit cost-of-service for gas of 35.72 cents per Mcf, employing techniques which have already been rejected by the Commission in *Phillips*. However, the instant decision, applying the methods and techniques approved by the Commission in *Phillips* (with some modifications as referred to above) derives a total jurisdictional gas cost-of-service for Tidewater in the amount of 11.45 cents per Mcf.

It is finally important to recognize that the difficult and basic issues refered to above, which necessarily arise in connection with the application of a cost-of-service method to the producers, and which necessarily consumed so much time and energy in the *Phillips* case and in the instant Tidewater proceeding, have now been finally resolved by the Commission in its *Phillips* decision. Accordingly these problems need no longer be the subject of further prolonged controversy.

We turn now to a discussion of the major cost-of-service issues which must be resolved in the instant Tidewater proceeding.

ALLOCATION OF JOINT PRODUCTION COSTS

In this proceeding, as in the *Phillips* case, a great deal of time and attention was devoted by the parties throughout the hearing to the question as to how joint production costs of the joint product leases should be allocated between liquids and gas. That important and basic question has now been firmly resolved by the Commission in its *Phillips* decision, where it adopted and approved the use of the *relative cost method* for this purpose. The Commission there stated:

> This method allocates the actual costs of joint oil and gas production in proportion to the known costs of producing each product separately. (Op. 338, p. 553)

In the *Phillips* case the unit cost for dry gas was determined from the records of Phillips' Natural Gas Department; and the unit cost for oil was obtained from the records of Phillips' Production Department relating to 100 percent oil leases.[3] The mechanics of the relative cost allocation process as applied in the *Phillips* case were described by the Commission in Op. 338 as follows:

> These unit costs for the two products are multiplied by the volumes of oil and gas produced on the joint product leases. This provides a tentative total relative cost for the oil and gas produced from such leases and a ratio of tentative gas cost to tentative total cost. This ratio is then applied to the total actual cost of he joint product leases to obtain the cost of the jointly produced gas. (p. 553)

It is concluded that here, as in the *Phillips* case, the relative cost method is preferable to any other suggested method for the allocation of joint production costs between liquids and gas, for the reason that cost allocations should be based, if possible, upon the factors which affect the various costs under consideration. The relative cost method has the advantage, over all other methods suggested for this purpose, of being a composite evaluation of all these factors without requiring a separate evaluation of each one. The logic of the relative cost method is succinctly and fairly stated in the intervenors' initial brief as follows:

> The logic of the relative cost method is that the physical characteristics of natural gas on the one hand and of liquids on the other affect their separate recovery from underground reservoirs and hence the incurrence of cost in connection therewith; and that the same physical characteristics affect the joint recovery and hence the joint cost incurrence involved in recovering them when they occur together in the reservoir. As is generally recognized and as in any event the Tidewater data made clear (T. 6774–6775), it is cheaper to raise liquid hydrocarbons from reservoirs in which they are found in conjunction with gas, the reasons being that the gas gas provides a source of energy for recovery of the liquids and modifies the physical characteristics of the liquids in such a way as to make their recovery easier, cheaper, and more complete than it otherwise would be: cf. Transcript pp. 1503-1540. It is logical, therefore, to divide the benefits of this efficient operation in some proportionate and equitable shares between the various products produced (T. 1677). The relative cost

[3] In order to obtain the unit cost for the 100 percent oil leases in the *Phillips* case it was necessary, among other things, to make an allocation of indirect expenses between the 100 percent oil leases and the joint product leases in Phillips' Production Department.

> method at least approaches this proportionate sharing since it depends upon what it apparently costs, or did cost to produce each product separately (T. 1677). (pp. 20-21)

Application of the relative cost method in the instant proceeding involves a particular problem not encountered in the *Phillips* case arising from the fact that Tidewater does not produce dry gas in any significant quantity. During the 1957 test year dry gas production accounted for less than 1 percent of Tidewater's total gas production and less than 1 percent of its test year gas revenues. (Exhibit 132, Sched. 5) Intervenor witness Kahn ultimately resolved this problem by developing a gas leg in which he combined with the few leases producing gas only in 1957, a "preponderantly gas" lease sample, composed of gas-condensate leases in which gas was the preponderant product —*i.e.*, where the wells contained 100 Mcf of gas or more per barrel of liquids, and in which gas revenues greatly exceeded liquid revenues.[4]

Tidewater's Btu Method

Tidewater contends that, because it has no substantial dry gas production, the relative cost method employed in the *Phillips* case is particularly unsuitable here; that its own experience provides no reliable figure on which to base the relative cost method of allocation in the instant proceeding.

Tidewater thereupon contends that its joint production costs should be allocated under the Btu method (*i.e.*, in proportion to the test year Btu production of each product)—"at least insofar as its gas-condensate properties are concerned". (initial brief, pp. 44–46; reply brief, pp. 24–28) In connection with this position, Tidewater stresses the fact that "by far the most important segment" of its gas production operations consists of production from gas-condensate leases, noting that in the test year 1957 its gas-condensate properties produced 64.80 percent of its total gas production and accounted for 74.46 percent of its total gas revenues. (Exhibit 132, Shed. 5) Tidewater contends that this preponderance of gas-condensate production

> . . . necessitates the use of an allocation method for production and exploration costs which recognizes the physical fact that gas-condensate reservoirs exist wholly in the gaseous phase. (reply brief, p. 25)

Tidewater's position with respect to the physical facts governing the operation of gas-condensate reservoirs and the conclusions to be drawn therefrom is set forth as follows:

> These gas-condensate leases are produced from reservoirs which contain hydrocarbons in the gaseous form at high pressure. When this single homogeneous substance is brought to the surface and the pressure reduced, it separates into liquids and gas. It is only after the production process is completed and all production costs have been incurred that the single gaseous form of hydrocarbons is divided into separate products (liquids and gas). In short, gas and liquids are in the *same form* throughout the incurrence of the joint production costs. The fact that the components of this wet gas stream are used for different purposes and have different values subsequent to completion of the production process does not change the fact that the production costs associated with one Mcf of such single homogeneous product are indistinguishable from the production costs associated with any other Mcf. (initial brief, p. 44)

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[4] The rationale supporting the use of this gas leg, and the Tidewater criticism thereof, will be discussed at length at a later point.

> These physical and operating facts conclusively show that for gas-condensate production the BTU method of allocation most closely approximates the actual incurrence of production costs. Therefore, since the allocation problem in this case relates principally to joint production costs incurred in connection with Tidewater's gas-condensate production, the BTU method of allocation is appropriate. . . . (initial brief, p. 45)

The obvious and complete answer to this Tidewater position lies in the fact that the Commission in its *Phillips* decision, in allocating joint production costs, applied the relative cost method uniformly and without differentiation to Phillips' gas-condensate leases as well as to its casinghead gas-oil leases. This was in spite of the fact that the greatest part of Phillips' production from joint product leases came from gas-condensate leases.[5] Although Tidewater in support of its instant position emphasizes the large proportion of its total gas production which comes from gas-condensate leases, it is interesting to note that Phillips' 1954 production of gas from gas-condensate leases, amounting to 78,499,506 Mcf, was substantially higher than Tidewater's 1957 gas production from gas-condensate leases, which amounted to 61,695,657 Mcf. (Tidewater reply brief, p. 24)

Tidewater attempts to play down the significance of the Commission's use of the relative cost allocation method in the *Phillips* case by noting that Phillips' production of gas from joint product leases amounted to only 19.01 percent of its total gas produced *and purchased* in 1954. Tidewater therefore suggests that any possible errors inherent in the use of the relative cost method could not in any event have had any very great impact upon the ultimate result in that case; that accordingly the use of the relative cost method provided no cause for serious concern in the *Phillips* case. By contrast, Tidewater notes that any possible errors inherent in the relative cost method could have a very substantial impact in the instant proceeding by virtue of the fact that it would here be applied to 99.43 percent of Tidewater's total 1957 gas sales, this being the percentage of its 1957 gas production coming from joint product leases.

This Tidewater argument is without merit. It may first be noted that the comparative figures used here by Tidewater create a rather distorted impression. Since we are dealing here with the problem of allocating the cost of gas *produced* from joint product leases, it is difficult to see the relevance of the fact that only 19.01 percent of the gas produced *and purchased* by *Phillips* in 1954 consisted of its own production from joint leases. A far more relevant statistic may be obtained by noting that 39.7 percent of Phillips' own 1954 gas *production* came from its joint product leases. Furthermore, it is perfectly clear that the Commission in its *Phillips* decision approved the use of the relative cost method for the allocation of joint production costs *as a matter of principle* (Op. 338, p. 553, *et seq.*) and there is no basis whatsoever for the inference that this approval was given grudgingly or with reservations.

In further support of its instant position, Tidewater (initial brief, pp. 45-46) quotes certain language used by the Commission at page 33 of its *Phillips* decision, in connection with the Commission's discussion at that point of the problem of distributing wet gas stream costs between extracted liquids and residue gas. Tidewater contends that this quoted language establishes the validity of the Btu method in the instant proceeding "at lease insofar as its gas condensate properties are concerned." (initial brief, p. 46) It is concluded,

[5] 20.9 percent of Phillips' 1954 gas production was from gas-condensate leases, with only 18.8 percent coming from casinghead gas-oil leases. The remaining 60.3 percent of production was from dry gas leases. (Tidewater reply brief, p. 24)

however, that this quoted language from the *Phillips* decision is totally irrelevant here. The problem of allocating joint *production* costs between gas and liquids, which is governed by the relevant engineering facts, involves quite different factors and considerations than the problem of distributing the costs of a wet gas stream entering an extraction plant between extracted liquids and residue gas. Furthermore, it is difficult to see how the *Phillips* decision can seriously be cited as authority for the instant Tidewater position when the Commission in that case, after employing the Btu method for allocation of wet gas stream costs between extracted liquids and residue gas, nevertheless used the *relative cost* method for allocation of the joint *production* costs of Phillips' gas-condensate leases, which amounted to 20.9 percent of its test year gas production.

As noted above, the entire Tidewater thesis here is that its gas-condensate production operations are marked by certain special and peculiar characteristics which allegedly render it inappropriate to apply to gas-condensate leases the same allocation method which may be regarded as suitable for the casinghead gas-oil leases. The special characteristic thus cited for the gas-condensate leases lies in the fact that they produce a single homogeneous substance, *in gaseous form;* and that it is only *after* the production process has been completed and all production costs have been incurred that the single gaseous form of hydrocarbons is divided into separate products (condensate liquids and gas).

However, it is important to note that the same situation applies with equal force to the casinghead gas-oil leases, where the gas is dissolved in the oil in the reservoir, and is first separated from the oil in the trap or separator which is usually located at the well or at tank batteries. The only difference lies in the fact that in gas condensate leases the single homogeneous substance is in the form of a vapor, or gas, until it reaches the surface—when a portion of the vapor condenses into liquid condensate upon the reduction of the pressure. The situation with respect to the casinghead gas-oil leases is the reverse—*i.e.*, the single homogeneous, substance in the reservoir is in the form of a liquid. When it comes to the surface, the gas is separated from the oil as a result of pressure reduction.[6]

As already noted above, the Commission in *Phillips* recognized no relevant difference between these two situations, and accordingly employed the same relative cost allocation method of joint production costs both in the case of single phase production of the gas-condensate (vapor) variety and single phase production of the casinghead-oil (liquid) variety.

As a matter of fact, the distinction sought to be made here by Tidewater between crude oil and condensate is largely a matter of semantics. In the stock tank, condensate *is* in effect a light, non-asphaltic *crude oil* of 45° APL or higher. As the Commission itself stated in *Phillips*,

> The contents of some of the recently developed gas-condensate reservoirs exist wholly in the gas phase; and a portion of the gas condenses naturally during the production process *into a liquid that is separated and sold as light crude oil.* (Op. 338, p. 559; emphasis supplied)

Similarly,

> . . . condensates produced from deep reservoirs are undistinguishable from nonasphaltic light crude oil . . . they are crude oil. (Stuart E. Buckley, *Petroleum Conservation*, AIMME, 1951, p. 106)

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[6] See testimony by intervenor witness Botset in the instant proceeding at 10:1524–25; testimony by Phillips witness Tarner in the *Phillips* case, 56:7902–3; Smith- Wimberly Report, Natural Gas Investigation, Docket No. G–580 (1948), at pp. 71–76, and 108.

Phillips witness Tarner testified in the *Phillips* hearing as follows:

> In most cases we handle the condensate as an oil. It is stored and sold in the same manner, *and it is sold on the same price basis as an oil.* (Phillips, 56:7905; emphasis supplied)

The fact is that condensate is, like crude oil, a primary source of gasoline and gasoline components. Condensates, after separation, are handled like other crude oils and are employed in the making of gasoline, jet fuel, kerosine, chemical materials, and other *non-heating* products.[7]

In the *Phillips* case the Commission rejected the *straight Btu method* for the allocation of exploration costs between oil and gas, stating:

> . . . such a method reflects only in part the potentialities of the hydrocarbon products. Oil and gas are not produced, purchased and used merely on the basis of Btu content or available energy. The transportation, refining, distribution and utilization factors are equal to or greater than the factors of exploration and development. As the examiner explains, the chief function of the oil industry is to provide fuel for transportation. Oil and its component, gasoline, are basically useful because they provide energy in compact, mobile and easily controlled liquid form. Actually, the heavier the crude oil, the higher will be its Btu content but the lower will be its gasoline content and its price. Gas, on the other hand, does not have the mobility of oil, for it must be carried in pipelines under pressure and used under limited conditions. Both oil and gas are used for the manufacture of chemicals and plastics which could not be properly compared on the basis of Btu. Thus if the Btu method is to be made practicable and useful for the allocation of costs it must be modified by the exercise of judgment based on the facts and the principles that guide producers in the incurrence of costs. (Op. 338, p. 556-557)
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> * * * * * * *
>
> . . . exploratory activities are directed to obtaining saleable products so that it seems reasonable that market relationships should also be reflected in the allocation. Furthermore, developmental activities are directed towards the production of known reserves and such activities would reflect market conditions. (Op. 338, p. 559)

Accordingly, the Commission in the *Phillips* case concluded that an economic factor of four (based upon and reflecting the ratio of the price of a barrel of petroleum to an Mcf of gas at the wellhead) must be applied to the straight Btu content of oil, as an adjustment factor for the Btu ratio

> that will have the effect of correcting its unreality and of avoiding imposing costs on gas consumers which should fairly be borne by the consumers of the ultimate products of the crude oil but also require gas to bear its proper share of the costs. (Op. 338, p. 560)

These identical objections to the straight Btu method are applicable with equal force to its use, as here proposed by Tidewater, for the allocation of joint *production* costs between liquids and gas. In view of the facts as developed above with respect to the nature and uses of *condensate*, such defects are equally obvious and equally fatal regardless of whether we are dealing with casinghead gas-oil leases, or with gas-condensate leases.

It is therefore concluded that there is no valid basis for adopting the Btu method, as proposed by Tidewater, for allocation of the joint production costs of its gas-condensate leases; that, on the other hand, the relative cost alloca-

[7] 1958 Minerals Yearbook, Vol. II, Fuels, pp. 329–346.

tion method *does* constitute an appropriate and acceptable way to measure the relative roles of the condensate and the gas in the incurrence of joint production costs on the gas-condensate leases, as it does in the case of the casinghead gas-oil leases. It will be recalled that at an earlier point, in explaining the rationale of the relative cost allocation method, it was noted that it is cheaper to raise liquid hydrocarbons from reservoirs in which they are found in conjunction with gas, since the gas provides a source of energy for recovery of the liquids and modifies the physical characteristics of the liquids in such a way as to make their recovery easier, cheaper and more complete than it would otherwise be. It was concluded that the relative cost allocation method represents a logical and appropriate manner in which to divide the benefits of this efficient operation in some proportionate and equitable shares between the various products produced.

The same situation applies with even greater force to the gas-condensate leases, since in some respects natural gas helps even more in the recovery of condensate than in the recovery of crude oil. Because of the very large volume of gas present per barrel of condensate in the gas-condensate leases, the liquid is actually "dissolved" in the gas phase and exists as a vapor. Since the condensate thus occurs in vapor form, it does not exhibit its usual (liquid) properties of surface tension and wettability and is not subject to the retentive force of capillarity in the reservoir pores. Accordingly, a high degree of recovery of the condensate is possible.[8] If the condensate existed by itself in the reservoir, it would be in liquid form (as a light crude oil) and would have to be recovered as a liquid, and its recovery, absent the lifting effect of gas, would be correspondingly more difficult.

In view of the facts as outlined above, it would be ironic if in the case of the gas-condensate leases, where gas makes an even more important contribution to the production of the liquids than in the case of the casinghead gas-oil wells, we were nevertheless to adopt an allocation method—*i.e.*, the Btu method as proposed by Tidewater—which charges a far higher ratio of joint production costs to the gas than is obtained under the relative cost method which is applied to the casinghead gas-oil wells. It should further be noted that the adoption of any such anomalous position with respect to the gas-condensate leases, as proposed by Tidewater, would have the most serious results here in view of the fact that Tidewater's gas-condensate properties produced approximately two-thirds of its total gas production for the year 1957 and accounted for more than two-thirds of its total gas revenues.

Tidewater's Use of Omnibus Relative Cost Factors

As earlier noted, Tidewater contends that because it does not produce dry gas in any meaningful quantity, its own experience provides no reliable figure on which to base the relative cost method of allocation; that, accordingly, if the relative cost method is to be used for any purpose in this proceeding, the Commission should adopt and apply to Tidewater the relative cost factors for "dry gas" and "pure oil" which were obtained from the record in the *Omnibus* proceeding.[9] Tidewater contends that these relative cost factors, based on the composite experience of 17 major oil and gas producers, are more appropriate than the relative cost factors developed by intervenor witness Kahn on the basis of Tidewater's own experience. Accordingly, in Appendix 3 of its initial

[8] See testimony of intervenor witness Botset, 10:1524–26. Similarly, see testimony of intervenor witness Kahn at 10:1666.

[9] *In the Matters of Champlin Oil and Refining Company et al.*, Docket Nos. G–9277, *et al.* The *Omnibus* relative cost factors were developed in Exh. 50–LC in that proceeding, which constituted part of a composite "industry" cost-of-service study.

brief, in constructing a cost-of-service "in accordance with procedures used by the Commission in the *Phillips* case", Tidewater uses the *Omnibus* relative cost factors throughout its entire relative cost allocation.[10]
The *Omnibus* relative cost factors thus used for Direct Lease Expense were $1.1225 for liquids and $0.02712 for gas—the liquids factor thus being 41.4 times as high as the gas factor. By contrast Intervenor witness Kahn used a relative cost factor for liquids of $1.572 and a relative cost factor for gas of $0.0261—so that his liquids factor was 60.22 times as high as the gas factor. (Exh. 180, Sched. 2)

For the relative cost allocation of Direct Net Investment, Tidewater used the *Omnibus* relative cost factor of $3.98046 for liquids and $0.29584 for gas—the liquids factor being 13.45 times as high as the gas factor. By contrast, Kahn used a relative cost factor of $5.196 for liquids and $0.2337 for gas. (Exhibit 180, Sched. 6)—his liquids factor thus being 22.23 times as high as his gas factor)[11]

It is of interest to note that the *Omnibus* relative cost factors thus used by Tidewater *for gas* are not very substantially different from the gas factors developed by Kahn in his Exhibit 180. The really major and significant differences between the Omnibus factors and Kahn's factors occur in connection with the relative cost factors *for liquids*.

It is important to recognize that a portion of this disparity between the *Omnibus* liquids factors and the factors derived by Kahn results from and reflects the fact that Kahn used a different type of liquids leg than was employed in the *Omnibus* relative cost study. The *Omnibus* study used a liquids sample composed of *all 100% oil leases* (*i.e.*, leases which produced no marketed gas). By contrast, for reasons which will be discussed at length in a later part of this decision, Kahn developed a liquids leg composed only of "crude only-pumping-nil gas/oil ratio" leases. In addition, the *Omnibus* relative cost study employed a liquids leg consisting of *all vintage* "pure oil" leases. By contrast, for reasons which will be explained in detail at a later point, Kahn's relative cost allocation of On-Lease Net Investment (Direct Net Investment) employed only *recent vintage* "pumping only" leases for the liquids leg.[12]

Since it is here concluded that there are valid reasons, on the merits, for adopting these particular Kahn techniques, it is clear that the use of the *Omnibus* relative cost factors, which were derived on the basis of quite different techniques, should be rejected in this proceeding.

Entirely apart from the above, however, it is concluded that the use of the *Omnibus* relative cost factors, as here proposed by Tidewater for the purpose of determining its just and reasonable rates in the instant proceeding, should be rejected outright as totally inconsistent with the strict conditions explicitly laid down by the Commission in the *Omnibus* proceeding, governing the limited use which was to be made thereafter of the producers' composite cost-of-service study. The use of such data in the manner here proposed by Tidewater would constitute a plain violation of the fundamental requirements of due process.

In order to understand the problem here presented, it is necessary to briefly summarize the background and history of the *Omnibus* proceeding. That pro-

[10] Since the *Omnibus* relative cost factors were available only for the year 1955, these same factors were used in Tidewater's Phillips-type cost study for both its test year 1955 (Appendix 3, Sched. 3) and its test year 1957 (Appendix 3, Sched. 2).

[11] Tidewater used the same relative cost factors for Indirect Net Investment and Indirect Lease Expenses which it applied for Direct Net Investment. Kahn, however, used a composite, conglomerate average ratio for his relative cost allocation of both Indirect Lease Expense and Indirect Net Investment.

[12] Kahn similarly applied this same technique for his gas leg in his relative cost allocation of On-Lease Net Investment.

ceeding was set up by the Commission in order to provide the parties with the opportunity to present

> generally applicable evidence relating to a theory or theories of rate fixing for sales of natural gas by independent producers, subject to the jurisdiction of the Commission, including evidence of a general economic or accounting nature, but excluding evidence applicable only to the cost of service or form and level of rates of any particular and individual Respondent.[13]

During the course of the *Omnibus* proceeding counsel for certain of the producers offered in evidence, as Exhibits 44–IC to 52–IC, what was described as a combined or composite industry cost-of-service study based on statistics supplied by some 17 independent producers. This particular 17-company producer group did not come into being as the result of any calculated attempt or design to select companies which would present a representative, composite average picture of the entire producer industry. Instead, it had its origin in the fact that some 18 independent producer companies had banded together and employed the auditing firm of Arthur Young & Company to prepare a composite cost-of-service study based upon their own operations. The Arthur Young firm submitted a questionnaire to all 18 of the companies, but received the requested data back from only 17. It then proceeded to prepare the composite cost-of-service study on the basis of the responses received from these 17 producers. (See *Omnibus* transcript, 31–LC: 3809–15; 32–LC: 4023–30).

When this composite cost-of-service study was offered in evidence in the *Omnibus* proceeding, Commission Staff Counsel and various intervenors objected on the ground that they would not be afforded an opportunity to cross-examine the individual producers whose responses had provided the basis for the composite study, and to check and test the underlying data. The Presiding Examiner in the *Omnibus* case thereupon excluded the composite cost study. However, the Commission by order issued January 9, 1959 reversed the Presiding Examiner and admitted the composite cost study "as statistical evidence". The Commission explained that this material was being received in the *Omnibus* proceeding merely for the limited purpose of serving as "statistical evidence in the nature of broad background material *and not for the purpose of establishing costs or rates for any single individual producer*" (p. 24, emphasis supplied); that the purpose was merely to bring before the Commission "materials of possible aid in assisting the Commission to arrive at a method or methods of testing independent producer rates"; that "*The evidence so received is not to be used to test the rates of any individual producers* but to aid the Commission in determining on general principles applicable to the rates of independent producers."; that "on this limited basis and for this general purpose, it is worthy of examination along with the other statistical and economic data already adduced" (p. 3 of Order; *emphasis supplied*). The Commission further suggested that when the individual producer rate cases should later come to hearing, the Presiding Examiner in each such hearing "can best judge the extent to which the parties can be relieved of the burden of cross-examination and detailed verification of this evidence. . . ." (p. 24)

Subsequent to the issuance of Commission order, the intervenors in the *Omnibus* proceeding (who now constitute the intervenors in the instant Tidewater proceeding) proceeded with the cross-examination of producer witness Porter who, as a member of the Arthur Young & Company auditing firm, had

[13] Order Reversing Ruling of Presiding Examiner Excluding Evidence, issued January 9, 1959 (21 FPC 22) (p. 24, footnote 1).

prepared the composite cost-of-service study. During the course of this interrogation, intervenor counsel requested that he be provided with: (a) the replies which had been submitted by the 17 companies in response to the Arthur Young questionnaire; (b) the lease data of the 17 companies, to be used in checking the responses made by them to the questionnaire. He stated that it was necessary for the intervenors to have this information in order to be in a position to conduct a meaningful cross-examination with respect to the composite cost-of-service study. Counsel for the producer group, *which included Tidewater Oil Company*, categorically refused to provide this information. (See *Omnibus* transcript, 32–LC: 4002-4003)

Intervenor counsel then made a statement on the record, which is quoted here because it effectively characterizes the dilemma with which the parties were thereby confronted in the *Omnibus* proceeding. He stated:

> As far as I am concerned, we are confronted here with the cost of service study presented by a very able witness who, on the witness stand, indicates in his opinion he has done a very wonderful job. And I am not in a position to say whether he has or has not. Because I don't know what went into the cost of service study. He has taken responses to questionnaires from 17 companies, which he indicates have been cleared by CPA's of accounting firms over which he had no direct control, and based upon that polyglot of information, he has prepared and set up one huge natural gas producing company. We don't have the individual companies, we don't have the individual figures for any particular company, not even by company name. All we have is a cost of service study set up in very fine folders, which we have got to take in perfect good faith, and which may be used against us down the road in any number of ways, and depending upon the Commission may be accepted or rejected in any number of ways, without any opportunity on our part to cross-examine it. (32 LC:4009-10).

Subsequently, on April 1, 1959 the *Omnibus* intervenors filed with the Commission a joint application for *subpoenas duces tecum* to produce the following evidentiary materials:

> 1. The responses made by each of the companies hereafter named to a questionnaire submitted by Arthur Young and Company for certain data, which data were in turn used by representatives of Arthur Young and Company in the preparation of exhibits 44–LC—52 LC inclusive, testified to herein by the witness, Stanley P. Porter.
>
> 2. Lease data either in the form of ledgers or lease-by-lease records based on ledgers or any other comparable data used by representatives of each of the named companies in preparation of the responses referred to in 1, above, together with all pertinent letters, memoranda, or other corporate papers necessary to a clear understanding of such lease records. (pages 1-2 of subpena application)

The joint application further stated:

> The data requested are essential to secure information as to whether the records of the responding producers had any relation whatever to each other. Absent reasonable consistency in the producer records, the study is obviously meaningless, and such consistency cannot be assumed because there is no uniform system of accounts for producers.
>
> * * * * * * *
>
> . . . we submit that the further data we request are absolutely essential to permit a determination by the Commission of the usefulness of the

> cost study. Without such data the cost study can have no meaning and will remain merely a collection of figures derived from unlike data furnished on varying bases by an infinitestimal sample of 17 producers out of some 5,000. Its usefulness or weight simply cannot be tested. (p. 4)
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> * * * * * * *
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> It would seem to be the Commission's intention that evidence presented herein subsequently be incorporated in the several separate proceedings without the need for repeating the presentation in each instance. It would follow, therefore, that these applicants face the possibility of being confronted at some future time with this very evidence (Exhibits 44 LC—52 LC) which they now seek to test by means of obtaining data referred to in 1. and 2. above. If they are denied access to such data now and if in some future proceeding this study is admitted into evidence without affording them an opportunity to test its validity, in such proceedings there can be no doubt that applicants will have thus been denied due process of law. (p. 4-5)

By order issued April 22, 1959, the Commission denied the intervenors' subpena application, referring to and quoting the conditions which it had laid down in its previous order of January 9, 1959, as to the limited use for which the composite cost study was there received.

We are now confronted, in the instant *Tidewater* proceeding, with the very situation which the *Omnibus* intervenors anticipated and feared—a situation in which Tidewater, which itself was a party to the *Omnibus* proceeding, now seeks in the instant case to make use of the *Omnibus* composite cost study in the very manner and for the very purpose which the Commission guaranteed, in its *Omnibus* rulings, would *not* thereafter be permitted—*i.e.*, as a basis for computing its own individual-company cost-of-service.

It is concluded that the use of the *Omnibus* relative cost factors for that purpose in the instant proceeding would constitute a shocking violation of good faith and due process, and the proposal is therefore categorically rejected.

In addition, however, it seems axiomatic to state that it is preferable in any event to allocate Tidewater's joint production expense and investment on the basis of an evaluation of *its own* particular experience and operations, and that it is accordingly desirable to construct the relative cost factors here on the basis of Tidewater's own actual experience.[14] As already noted, however, Tidewater justifies its use of the *Omnibus* factors on the ground that it has no substantial dry gas production of its own, and that its own experience accordingly provides no reliable basis for the development of a gas leg. Tidewater witness Joseph conceded that Tidewater's own experience does provide a reliable basis for development of a liquids leg, but concluded:

> since it is necessary to obtain the sample pure gas cost from some other source I thought it best to go to the other source for both the pure gas cost and the pure oil cost. (37:5772)

However, as will now be developed in detail, it is concluded here that the gas leg derived by intervenor witness Kahn on the basis of Tidewater's "preponderantly gas" leases does constitute a satisfactory technique for development of a relative cost gas factor based upon Tidewater's own experience. In fact, as already noted, this technique resulted in a relative cost factor which is not very substantially different from the *Omnibus* "dry gas"

[14] This, of course, was the technique followed by the Commission in the *Phillips* case.

factor used by Tidewater. Under the circumstances, the Tidewater assumption that its own experience "simply provides no reliable figure on which to base the relative cost method of allocation" (initial brief, p. 48) is not valid.

Intervenor's Gas Leg

In Kahn's original 1955 test year cost-of-service study (Exhibit 75) he used a gas leg composed of "gas-only" leases, accounting for slightly more than 1 percent of Tidewater's total gas production by volume. This resulted in a relative cost gas factor of $0.0394 per Mcf. Kahn recognized at the time that this provided a thin sample. He accordingly tested this figure against the results obtained by the use of other samples and other methods. As a result of these tests, he concluded that the factor of $0.0394 was a relatively high one to use for the hypothetical "single-purpose" cost of gas; and that "beyond 'single-purpose' lease operations." (10:1682) However, in the absence of information permitting him to develop a more representative picture of the doubt it tends to exaggerate the on-lease expenses of gas production on production costs of non-associated gas, Kahn adopted the figure of $0.0394 "with the warning that it is probably excessive." (10:1683)

Subsequently, however, in connection with his 1957 test year cost-of-service concluded that the "gas-only" category now represented an aggregate produc- study (Exh. 150) Kahn developed a new type of gas leg consisting of two groups of leases: (a) a category which he characterized as the "preponderantly gas" leases, being Tidewater's gas-condensate leases which produced in excess of 100 Mcf of gas per barrel of petroleum; plus (b) the gas-only leases which showed both production and expenses.[15] (45:6777) Kahn explained that this change in the character of his gas leg resulted from the fact that data subsequently provided for the record by Tidewater witness Joseph had made it clear that many of the leases which Kahn had previously regarded as "pure gas" leases, on the basis of information in the early Tidewater work papers, actually produced liquids and accordingly did not properly belong in the "gas-only" category.[16] On the basis of this corrected information, Kahn concluded that the "gas-only" category now represented an aggregate production of only approximately 546,000 Mcf, representing approximately 6/10 of one percent of the company's total gas production. (45:6775) He also concluded that this reduced "gas-only" sample was subject to further difficulties (a) because more than half of its production was from leases which listed no expenses at all; and (b) because almost ¾ of its total expenses were registered on a group of *non-producing* leases, which Tidewater had classified as "gas-only" simply on the basis of an analysis of their underlying reserves. (45:6775–76) Under all the circumstances Kahn concluded that the "gas-only" category had turned out to be "erratic and unrepresentative".

Kahn accordingly developed in Exh. 150 a new gas leg composed largely of "preponderantly gas" leases (being the gas-condensate leases with a gas-oil ratio in excess of 100 Mcf per barrel), whose production represented approximately 10 percent of the total gas sales of Tidewater's Southern and Central Divisions. He stated:

> This provided me with a very broad sample which is in itself desirable wherever possible. . . . (48:7027)

[15] These "preponderantly gas" leases produced 9,707,282 Mcf of gas in 1957, while the selected "gas-only" leases produced 244,166 Mcf. (Exh. 150, Sched. 4)

[16] Kahn found that Tidewater's "pure gas" lease category included a fairly large group of leases which actually produced liquids as well as gas, simply because they showed no sales of liquids. (47:6899–6900) He also found that Tidewater's "pure gas" category included leases where some liquid was produced, but where the liquids were extracted in plants owned by other companies and Tidewater accordingly did not record such liquid production on its own books and records. (45:6772; 47:6923; 48:7023).

And he concluded:

> I am convinced that the resulting figure of 2.59 cents per Mcf, derived from this much broader sample of gas-condensate leases, together with those in the gas-only category which show both production and expenses, is a highly reliable indicator of the on-lease cost of producing gas in the absence of oil (45:6777)

Kahn had called attention in his Exhibit 150 cost study to the fact that the "preponderantly gas" lease category there employed excluded

> a number of leases in District 16–3 with gas-liquids ratios above 100 Mcf per barrel, where the charge for depreciation and depletion is not distributed among the leases in the district. (Exh. 150, Shed. 4, Footnote 5) [17]

Although Kahn recognized that these particular District 16–3 leases met the standards which he had established for his "preponderantly gas" category, he originally did not find it possible to include them because he had been unable to obtain the depreciation and depletion charges properly assignable to those leases from the Tidewater books and records. Subsequently, during the latter stages of the hearing Tidewater made available certain information showing how the depreciation and depletion charges should be distributed to these District 16–3 leases. (49: 7074–75) As a result of this new information, Kahn thereupon added the District 16–3 leases to his "preponderantly gas" category in his final 1957 test year cost study, Exhibit 180.[18] The effect of this change was to double the size of the gas leg, with the result that the "preponderantly gas" category finally accounted for no less than 22 percent of the total production of the Southern and Central Divisions. (53:7485) The end result was to increase Kahn's gas factor from 2.59 cents per Mcf to 2.61 cents per Mcf, and to increase the ultimate on-lease expense allocated to gas from 1.14 cents per Mcf to 1.42 cents per Mcf.

Tidewater critizes Kahn's use of a gas leg composed largely of the gas-condensate leases with a gas-oil ratio in excess of 100 Mcf per barrel (the "preponderantly gas" lease category), contending that joint product leases should not be used to determine the relative cost factors allegedly representing the cost of producing *one* of the joint products in the absence of the other. In this connection, Tidewater emphasizes the fact that the Commission in its *Phillips* decision used only dry-gas leases for this purpose.

In addition, Tidewater attacks Kahn's adoption of "a gas-oil ratio in excess of 100 Mcf per barrel" as his standard for the "preponderantly gas" lease category, characterizing this as merely a "subjective grouping of certain joint production leases", and as

> an arrangement which first determines the answer and then dips into a huge volume of detail in the record for the selection of those leases which

[17] The District 16–3 leases were in the Hollywood Field, Terrebonne Parish, Louisiana.

[18] The Tidewater statement (initial brief, p. 49) that this occurred after Kahn was "*confronted* with the fact that the sample set of 'perponderantly gas' leases used in their initial 1957 cost of service presentation (Exhibit 150) did not contain certain important leases in the Hollywood Field, though such leases met the definition and standards which the Intervenors themselves had established"—contains a completely unwarranted inference. This point was first raised by Tidewater counsel during his cross-examination of Kahn at an April 20, 1960 hearing session. (48:7037) However, as noted above, it was Kahn himself who had directed the attention of the parties, *six months earlier*, to the fact that his Exh. 150 did not include the District 16–3 leases—Exh. 150, Sched. 4, footnote 5. (49:7074) Under the circumstances, the April, 1960 interrogation by Tidewater counsel hardly constituted a "confrontation".

> will provide the desired allocation ratios and lend some color of rational support for an answer which is inescapably arbitrary. (initial brief, pp. 48-49)

Tidewater states:

> Obviously there is no way to tell whether leases producing 100 Mcf, or more, of gas per barrel of liquids provide a more representative cost of gas alone than leases producing 98, 99, etc., Mcf per barrel of liquids.

It is concluded that there is no valid basis for this Tidewater charge that the standard referred to above represented an arbitrary and subjective selection of leases merely designed to support a pre-determined answer. Instead, bearing in mind the practical problem presented in this proceeding that Tidewater itself has no substantial dry gas production, the standard thus employed for the "preponderantly gas" lease category seems reasonable and makes sense in view of the following facts as noted by Kahn:

(1) that 90% of the revenues from such "preponderantly gas" leases were obtained from gas;

(2) that the State of Texas classifies wells as gas-wells if they produce in excess of 100 Mcf per barrel of petroleum;

(3) that it has been the practice of the Federal Power Commission staff in general:

> to consider as essentially gas, essentially dry gas leases, those in which liquid accounted for ten percent or less of revenue. And that accorded fairly closely with the State of Texas designation. (48:7025)

It should also be noted that in spite of its attack along the lines referred to above, Tidewater does not here suggest that the gas-condensate leases employed in Kahn's "preponderantly gas" lease category constituted unrepresentatively low-cost leases.[19]

Finally, it is of the utmost importance to note here that in employing these particular gas-condensate leases as his "preponderantly gas" lease category for the development of his gas cost factor, Kahn treated the *entire* on-lease cost of these gas-condensate leases as the *gas* cost, and did not charge or assign any portion of such costs *to the liquids* which were produced by these leases. Kahn stated:

> I think that it is clear that to the extent that these are not pure, 100% gas leases, that one may contend that the imputation factor derived from them is high in the sense that so far as the leg is concerned there is no attribution of any costs to liquids. I would say that was the primary defect.
>
> But I regarded the offsetting advantage of getting such a large leg in so widely representative a sample, whose size, incidentally, increases enormously now that we can put the Hollywood Field leases in, as far outweighing this particular disadvantage. (52:7403)

It is difficult to see how Tidewater under these circumstances can be heard to complain that Kahn's use of his "preponderantly gas" lease sample was arbitrary or unfair.

It may be recognized, as stressed by Tidewater, that the gas leg as thus developed by Kahn in this proceeding was somewhat different from the type of gas leg employed by the Commission in its relative cost allocation in the

[19] No such suggestion could seriously be made since the producers themselves have uniformly stressed before this Commission that the gas-condensate leases represent relatively high-cost production.

Phillips case. However, it should also be recognized that variations in operating factors or conditions between one producer and another may conceivably render it desirable or necessary in some cases to apply the relative cost method in a manner which represents some modification or adjustment of the precise method employed in the *Phillips* case. Such a departure under such conditions should not, however, be regarded as objectionable *per se*. The Tidewater insistence that this Kahn departure from the precise application of the relative cost method employed in the Phillips case constitutes a fatal defect in the instant proceeding represents an inflexible and rigid approach which is neither useful, necessary, nor desirable in dealing with problems of this character.

Intervenors' Gas Volume Adjustment

The gas volume figures used by Tidewater represent marketed (or net) production. Before applying his relative cost method to allocate on-lease expense and on-lease investment, intervenor witness Kahn adjusted the 1955 marketed gas volumes upward by 24.6 percent (Exh. 75–B, Sched. 6) and the 1957 marketed gas volumes by 20.85 percent (Exh. 150, Sched. 5, and Exh. 180, Sched. 6), in order to determine and reflect the volumes of gas actually produced at the wellhead—*i.e., gross* wellhead production.

In explaining the basis for this volume adjustment, intervenors noted (initial brief, pp. 22-23) that the gross production of gas on joint-product leases is typically far in excess of the net production by virtue of returns of gas to the reservoir, venting, and flaring. The intervenors contend that the cost of producing that portion of the gas on the joint leases which is either vented, flared, or returned to the reservoir is clearly attributable to the liquids and should be charged thereto; that it is accordingly necessary to adjust the marketed production figures presented by Tidewater upwards in order to obtain an estimate of the cost of producing the gross production of gas, and then to attribute the cost of producing the difference between gross and net production to the liquids.

Intervenor witness Kahn testified, in this connection:

> Any expenses appropriately allocable to the production of gas on joint leases is clearly incurred in the gross production of that gas, regardless of what proportion thereof is flared or vented, or returned to the reservoir. Expenses incurred in the production of gas that is not sold as such are correctly attributed not to the gas but to the production of the liquids, which are essentially responsible for these practices that create a discrepancy between total and marketed production. (31:4719)

With respect to gas vented or flared, he explained:

> Since the so-called net production is really marketed production, there would also be wasting of gas. That is, it comes up, it is not put back into the ground, but it is burned, or it is flared in some way. Now, that venting and wasting, it is my understanding, occurs primarily on oil wells. There is no reason to vent or flare gas that is in gas-only wells. But if you are producing oil and you are dying to sell the oil, and the oil is valuable, and you cannot find a market for the gas, then to the extent the states let us, you may let the gas go to waste.
>
> Well, the question then is should the cost of producing that gas that is wasted in order to recover the oil be imposed on the people who buy some of the other gas that you sell? So those would be the two main adjustments. (Tr. 4097)

In further support of this volume adjustment, the intervenors explained (initial brief, pp. 23-24) that this particular correction represented only partial recognition of the fact that on the joint-product leases it is the gas that plays the important role in lifting the liquids, rather than the reverse; that accordingly, instead of simply dividing the economies of joint production equally between the products in proportion to their single-production cost, it was felt desirable to give some additional recognition to the contribution of gas to the liquids; that, lacking any other method for giving this recognition, the use of gross rather than net gas production, in the manner described above, was accepted as giving partial credit to gas for its facilitating role in the production process. Intervenor witness Kahn made this point as follows:

> I thought it appropriate to modify the precisely proportionate reduction in expenses imposed on both products, because I was seeking some method of giving gas credit for lifting the liquids, and that method was the one we have described of imputing the single purpose product cost to the gross or estimated gross production of gas. And then on the basis of the fact that the difference between gross and net production of gas, and the costs justly attributable to that difference, are appropriate attributable to raising the liquids, imposing on gas only a total burden equivalent to what would be appropriate to the marketed production of gas. (50:7116)

And at another point he stated:

> The relative cost method without adjustment divides the economies of joint operation of wells precisely—proportionately among the gas and the liquids that the gas helps raise.
>
> And in my very beginning testimony I said that this raised a question about whether there was not some adjustment, rough or otherwise, that could be made to reflect the fact that this distribution contains within it the implicit assumption that the liquids helped raise the gas, just as much as the gas helped raise the liquids, an assumption contrary to fact. Indeed, the fact is the very opposite, that the necessity for lifting the liquids in a sense makes more difficult the recovery of the gas.
>
> I then said in my redirect that one approximation or one attempt to give gas this measure of credit was to use the particular correction that I have described with the logic that it contained that this was merely one rough way and an inadequate way of giving gas—shall we say, recognizing the physical situation that I have described. (50:7165-7166)

Although Tidewater does not raise any question with respect to this particular rationale in its discussion of the instant gas volume adjustment, at a later point in its initial brief (p. 50) in connection with its attack upon the "liquid leg" employed under Kahn's relative cost method, Tidewater raises a doubt as to the propriety of crediting gas for its role in lifting the liquids. In this connection, it contends that the Commission in its *Phillips* decision recognized that the alleged benefit of gas in the lifting of liquids is speculative and not susceptible to measurement, quoting the following Commission language:

> The record does not finally resolve this question nor does it provide a way of computing the credit for any supposed lifting effect of the gas.
>
> In fact, we think that it would be almost impossible to compute the value of the lifting effect of gas in oil production. Furthermore, it can be said that the lifting effect of gas is not so much a reason to give a credit to gas, but reason to increase the value of gas, for lifting oil is a very valuable use for gas. (Op. 338, p. 555)

The meaning and purpose of the last sentence in the above-quoted statement from the *Phillips* decision is obscure and could not properly be regarded as a Commission finding on this point. The lifting function performed by gas for the benefit of the liquids in a joint product reservoir does, of course, represent "a very valuable use" of such gas for the benefit of the producer. However, this "valuable use" obviously does not increase the value of the gas *to the gas consumer*, and should not be treated as a justification for increasing the price paid by the latter. Rather, it represents a service of value *to the purchaser of the liquids*, and it would therefore seem appropriate that the liquids should be charged with some portion of the gas cost in return for this contribution. The Commission in its *Phillips* decision correctly concluded that there was no basis *in that proceeding* for determining a credit to be applied to gas for this lifting function, in view of the fact that the record there made admittedly did not provide any adequate basis for computing any such credit. (Op. 338, p. 555) The situation is quite different in the instant Tidewater proceeding, where the intervenors (through their witness Kahn) have developed, presented and supported the gas volume adjustment discussed above as a method for providing a partial credit to gas in return for this lifting function. The important thing to bear in mind is that the Commission is here dealing with a field in which there are still many lessons yet to be learned. It would be neither useful nor necessary in the public interest, to take the position here that the problem must be regarded as forever insoluble merely because no adequate solution was presented in the *Phillips* case.

In determining that a gas volume adjustment of 24 percent was required for 1955 and 20.85 percent for 1957, in order to convert Tidewater's marked production figures to gross gas production, Kahn relied upon information supplied by Tidewater to the effect that their experience in this connection would closely approximate that of the country as a whole. He accordingly obtained his gas volume adjustment ratio from the bureau of Mines nationwide figures.[20]

Kahn explained:

> The Tidewater Company representatives had agreed to try to obtain for me information showing the Company's gross, net, and marketed production of natural gas, in a form corresponding to the statistics compiled by the Bureau of Mines. In a letter of June 26, 1958, from Mr. Robert O. Koch to Mr. William R. Duff, the Tidewater Company notified us that it would require an extended effort to compile this information, and offered the opinion 'that the percentage of the volume of gas that is nationally used for the above purposes will approximate the same percentage of Tidewater's volume of gas that is so used.' Accordingly, I applied the national figures for 1955, which shows a gross natural gas production 24.6 per cent higher than marketed production, to Tidewater. (31:4719–20)

The mechanical steps of Kahn's volume adjustment were carried out as follows. He first increased Tidewater's marketed production figure for gas by the above-mentioned ratio, to produce an estimated gross production of gas on the joint leases. He then completed all the steps of the relative cost method on that basis, to determine the on-lease expense allocated to the gross production of gas. This total was divided by the estimated gross production of gas,

[20] The 1957 adjustment figure of 20.85 percent was derived from information on page 312 of "1958 Minerals Yearbook, Vol. II, Fuels", where it appears that the quantity of repressured, vented, and wasted gas equalled 20.85 percent of gas marketed and consumed by producers in 1957.

to determine the unit cost of producing all the gas that was actually produced. In the final step, this unit cost figure was multiplied by the net (or marketed production of gas), in order to arrive at the cost to be charged to the marketed gas. The remainder of the gas cost (*i.e.*, the cost of the non-sold gas) was charged to liquids. (31: 4720–21; 27:4093–94)

As pointed out by Staff (initial brief, p. 13), this gas volume adjustment follows the Commission approach in *Phillips*, where the cost of extraction losses, gas returned to leases, and gas vented, was allocated out of the jurisdictional gas cost-of-service. (Op. 338, p. 564, Appendix 9 and 10); as further clarified in Commission Order Denying Rehearing, November 25, 1960, at p. 1010 and in Appendix 9, Revised) Under the *Phillips* technique the cost-of-service for jurisdictional gas was not charged with that portion of the total cost of the wet gas stream which was determined to be allocable to the gas returned to leases for repressuring and to the gas vented or flared.

Tidewater states (initial brief, p. 37) that it "does not object to this adjustment of test year sales volumes for the purpose of estimating wellhead raw gas volumes . . .". In fact, it states at a later point (initial brief, p. 94):

> Since Tidewater records show recorded gas *sales* volumes instead of gross *production* volumes, it was necessary to estimate the volumes of wet gas actually produced at the wellhead.

However, Tidewater strenuously argues that if such an adjustment is to be made, it requires a corresponding reduction in the wellhead liquid production volumes; that Kahn's failure to make such a corresponding reduction of liquid production volumes has the effect of imposing a double, or duplicate charge for the cost of the liquids—*i.e.*, both (1) at the point where they are produced in a gaseous phase at the wellhead, and (2) at the point where they are extracted in the gas processing plants. (initial brief, pp. 38-39)

It is important to recognize at the outset that this Tidewater position stands or falls upon the suggestion or assumption, made and pursued at length by its counsel during an extended interrogation of intervenor witness Kahn, that the Bureau of Mines national figures for (a) repressured gas (gas returned to reservoir) and (b) vented or flared gas, representing the difference between gross and net (or marketed) production, *also included shrinkage* (*i.e.*, the effect of the plant extraction of liquids from the wet gas stream upon the volume of gas reamining). The entire point made by Tidewater here is that if the figures for repressured and vented gas, which were used by Kahn to obtain his gas volume adjustment factor, also included shrinkage, then the effect of his volume adjustment would be to charge crude oil and condensate with the cost of such extracted liquids. Tidewater points out that plant liquids are *already* included in its recorded total liquid production,[21] which under the relative cost method shares an allocated portion of the joint product lease costs; that accordingly, unless a corresponding amount of plant liquids are removed from the total liquids production volume, the net effect would be to impose a double or duplicate charge on the plant liquids.

As will now be made clear, however, it appears that the Bureau of Mines figures for repressured and vented gas (employed by Kahn in this connection) do *not* include shrinkage—and this would appear to destroy the entire basis for this Tidewater position.

As already noted, intervenor witness Kahn at an early stage of the proceeding had requested Tidewater to provide him with the figures as to its own *gross* gas production—this information being peculiarly and solely within Tidewater's own possession. Tidewater nevertheless informed the intervenors

[21] Tidewater Exh. 129, Sched. 5; Appendix 3 to Tidewater initial brief, Sched. 2, p. 6.

that the compilation of such information would require an extended effort on its part, and suggested (as an acceptable alternative) that the nationwide ratio of gross production to net production would be approximately the same as its own experienced ratio. It was in reliance upon this Tidewater suggestion that Kahn thereafter obtained and relied upon the Bureau of Mines nationwide figures as a basis for the instant gas volume adjustment.

In spite of the facts as outlined above, Tidewater counsel in the course of his cross-examination of Kahn during the latter stages of the hearing devoted a great deal of effort to suggesting that the Bureau of Mines nationwide figures for (a) repressured gas and (b) vented or flared gas *included shrinkage*, and proceeded to attack Kahn's gas volume adjustment on the assumption that this was the fact. (50:7138–56) Kahn at this point readily agreed that if the Bureau of Mines data actually did include shrinkage, it would then be appropriate to make a corresponding reduction in the recorded liquid production volumes in order to avoid a duplicate charge to liquids, and he suggested:

> . . . there is really nothing to do but look to the Bureau of Mines and see if it does. (50:7156)

Tidewater counsel thereupon made it perfectly clear that his whole argument hinged upon whether the Bureau of Mines data in fact included shrinkage, stating:

> Q. So, really, I think we can agree, Doctor Kahn, that the determinative question is whether or not the 24.6 per cent includes shrinkage or not?
> A. I believe that is right. (50:7157)

Because of the unsatisfactory situation created on the record as the result of the uncertainty thus raised by Tidewater counsel, who himself showed no disposition to resolve the doubt by any evidence of his own, the Presiding Examiner suggested at the hearing session on April 22, 1960, that the parties contact the Bureau of Mines during an extended noon recess and obtain the precise answer—one way or the other. Later that day, at the afternoon session, Tidewater counsel simply reported that his own efforts had been unsuccessful and dropped the matter. (50:7169)

Doctor Kahn, however, testified as follows as to the results of the inquiry which he had made at the Bureau of Mines during the noon recess:

> I got in touch with Mr. Ivan Avery, who is chief of the section on natural gas, natural gasoline and carbon black of the petroleum economics branch of the Bureau of Mines. I was referred to him by two different people as being the expert on the contents of the statistics in question.
> Mr. Avery tells me that there is no adjustment for shrinkage in the difference between gross and marketed production, and that there could not be, because of the way in which these figures are compiled.
> The figures that this estimating process begins with are the figures for marketed production. These figures he tells me are very firm, they are figures that come from the companies. The Bureau then builds up to the estimate of gross production, first by adding the estimated volumes used for repressuring. And these figures too, he tells me, are very firm, that is, they are very confident of their validity, they are based, he said, primarily on information from the companies, and he said there was no possibility that those figures could contain an element of shrinkage or the reverse of shrinkage if you build it back up.
> And then secondly, they make an estimate of losses by venting and flaring. This figure, he said, is not as reliable a figure, but again there is no

reason for that figure to include an allowance for the opposite of shrinkage—you understand, it is the opposite, because we are building back up now.

So I put the question in another way, I said, is there any reason, then, to believe that the market production figure would be shrunk down? And he said specifically the marketed figure would not be shrunken down in any way.

I then asked, 'Would there be wet gas, then, in your marketed production?' And he said, 'Yes, there would be wet gas in the marketed production figure.' He was not explicit about how much he thought was wet and how much dry, but the significant point that he emphasized was that the estimates of the figures that it would take to go backwards from marketed up to gross are estimates of what they purport to be, directly made by the Bureau, and would not therefore be subject to the defect from our standpoint that we discussed before lunch.

PRESIDING EXAMINER: Dr. Kahn, in order to fit your answer into the context of the type of questions which Mr. Atwell was asking before the noon recess, would I be correct in saying that the effect of what you are saying is that if we accept at face value what Mr. Avery of the Bureau of Mines told you, that this indicates to you that the category of gas vented and wasted in the Bureau of Mines source material does not include shrinkage? (50:7170–72)

* * * * * * *

A. That is right. It does not include any factor for shrinkage—it does not include shrinkage. (50:7170–72)

* * * * * * *

BY MR. ATTWELL

Q. Now, did you explain to Mr. Avery what use you were making of the Bureau of Mines figures?

A. Absolutely not.

I began the conversation by saying that a question had been raised about the mining of the gross and the marketed production figures, and specifically the question was whether the difference between them was in any way explicable by shrinkage, and he proceeded then to explain along the lines that I have indicated. (TR 7173–74)

In spite of this testimony, Tidewater counsel expressed continued dissatisfaction with the situation, suggesting that it was his "understanding" that when Tidewater itself reports such figures to the Bureau of Mines, those figures do include shrinkage; that other companies probably make their reports to the Bureau of Mines in the same way. He further suggested that Kahn might have misunderstood what he was told by the Bureau of Mines, or that error may have occurred in some other way. The following colloquy then occurred:

MR. ATTWELL: Mr. Examiner, I think before I give you a direct answer to your question, I might state that Mr. Avery is a pretty busy man. We had a rather long session with Mr. Avery, and I don't know whether I ought to put myself on the stand or Mr. Koch or Mr. Joseph. You know sometimes you talk to these people and Dr. Kahn gets one impression and we get another.

I am not saying that he is not absolutely correct in his impression, I am not saying that he is not entitled to it.

PRESIDING EXAMINER: Suppose, for example, you would want to produce evidence to show that the official in the Bureau of Mines said

something to you about the subject which is inconsistent with the information Dr. Kahn got from him; is that what you are suggesting?

MR. ATTWELL: I wouldn't say it was directly inconsistent. To summarize it, what he told us, in my opinion, was that he flatly didn't know and couldn't tell.

PRESIDING EXAMINER: That was interesting, but unless I knew what kind of questions you put to him, I wouldn't have any way of evaluating whether the answers were meaningful. Perhaps you didn't do as good a job of putting questions to Mr. Avery as Dr. Kahn did.

MR. ATTWELL: Perhaps we did a better job, Mr. Examiner.

I don't think we know what questions Dr. Kahn exactly put to Mr. Avery.

THE WITNESS: I am under oath.

MR. ATTWELL: I will be happy to take the witness stand if the Examiner wants me to do so.

PRESIDING EXAMINER: The way I am going to leave it, Mr. Attwell, is that you can make any argument you care to in your briefs as to the 24.6 percent adjustment, and that argument will have to be based on data in this record. If the data in this record is not as satisfactory as you would like it to be, my feeling is that Tidewater is the one party in this whole proceeding that could have made the data more satisfactory, and Tidewater didn't do it—I am not criticizing Tidewater for not making a lengthy study, but you didn't make it, and that is it as far as I am concerned.

MR. ATTWELL: I might say one thing in reply to that, Mr. Examiner. Tidewater didn't say, in response to Dr. Kahn, the difference between our gross marketed production and net marketed production is precisely the same thing as the Bureau of Mines reports, they simply said that it would probably approximate that same percentage.

Now, Tidewater didn't investigate at that time as to what exact elements composed the Bureau of Mines data.

PRESIDING EXAMINER: Mr. Attwell, at that stage of the proceeding, which was long before you came into the picture, we had reached a point where I insisted that the intervenors make clear to Tidewater all the further data the intervenors would need for this proceeding, and the intervenors did so, and one of the types of data requested was the type we are discussing now. And it was in response to that that Tidewater then, through Mr. Koch, wrote a letter to the intervenors suggesting that instead of Tidewater making that study, that the information could be obtained from the national figures.

I just feel there is nothing more to be added to that, whatever argument you want to make on the point will have to be made in your brief.

BY MR. ATTWELL:

Q. Let me ask one concluding question on that subject, Dr. Kahn—maybe two questions.

Just to be sure I understand your testimony to the Examiner relative to your—I believe the telephone conversation, wasn't it, with Mr. Avery?

A. That is right.

Q. Is it the purport of your testimony that the Bureau of Mines figures that you relied on to make your volume adjustments just do not include shrinkage in any of the items which we were talking about this morning?

A. That is right. This is merely another way of saying that the Bureau of Mines figures in fact are what they purport to be, which I assumed they were at the outset. (50:7177–80)

Under the circumstances as outlined above, it is here concluded that it would be completely unjustifiable to give any serious weight to the doubt self-generated by Tidewater with respect to the meaning of the Bureau of Mines figures—when all doubts could readily have been dispelled if Tidewater had seen fit to provide its own figures.

Since it is thus here concluded that the Bureau of Mines figures for repressured and vented gas, which were added to marketed production to obtain the gross production level, do not include shrinkage, it is clear that Kahn's estimated gross gas production volumes, derived by application of the Bureau of Mines nationwide ratio, do *not* include liquids. There is accordingly no merit in the Tidewater contention that the failure to make a corresponding reduction here in its recorded liquid volumes "has the effect of including liquids in both gross gas production volumes and liquid production volumes" (initial brief, p. 39), and that the result is "to duplicate the costs allocated to liquids". (initial brief, p. 37) On the contrary, the effect of Kahn's gas volume adjustment is merely to charge liquids with (a) the cost of the gas which is used for repressuring, and (b) the cost of the gas which is vented or flared—costs which should properly be charged to the liquids since this particular disposition of gas is dictated by operating considerations relating to the liquids. It was for this very reason that the same costs of gas returned to leases, and gas vented, were allocated out of the jurisdictional gas cost-of-service in the Commission's *Phillips* decision, *supra*.

Tidewater suggests as another claimed error in Kahn's application of his gas volume adjustment, that the Bureau of Mines figures for repressuring, which were the basis for his 24.6 percent factor, included *some* gas returned to reservoir on "liquids only" leases; that it was improper to include repressured gas from such leases in the Bureau of Mines figures, since Kahn's cost-of-service charged *all* production costs of the "liquids only" leases to the liquids alone. (initial brief, pp. 40-41)

Kahn characterized this as a *de minimis* situation, noting that the ultimate production of Tidewater's "liquids only" leases was

> only about three hundred thousand barrels, whereas the aggregate condensate production of the Southern and Central Divisions is about 3.9 million barrels, or approximately twelve times as much, and to all of this, as well as to the fifteen million barrels of crude oil produced in the presence of gas, gas also makes its contribution. (50:7181)

He concluded:

> liquids only leases accounted for only a very small proportion of Tidewater's total liquids production.
> So that the extent to which this is a double dip is undetermined but, I judge from those figures, small. (52:7399)

Kahn further noted that his proposed gas volume adjustment only partially compensated for the lifting service performed by gas in any event, and he accordingly felt that there was room for some slack here. (50:7165–67) Under the circumstances it is concluded that this point does not merit further consideration.

Intervenors' Liquid Leg

In Kahn's latest 1955 cost study (Exh. 75–B), and in his 1957 cost studies (Exhs. 150 and 180) he employed for his relative cost allocation of on-lease expenses a "liquid leg" consisting of the "crude only-pumping-nil gas/oil ratio" leases. These were crude only leases which had all wells on the pump, and with a negligible or nil production of gas per barrel of oil.

Tidewater charges that:

> Throughout this proceeding, as their various cost of service studies were presented, the methods, principles and costing techniques were constantly changed to coincide with the subjective ideas of the Intervenors' cost of service witness. The most flagrant example of the Intervenors' vacillation was their use of continually changing samples in order to establish relative cost factors for the allocation of production expenses and investment. (initial brief, p. 21)

Tidewater cites as an example of intervenors' alleged vacillation the fact that in Kahn's earliest 1955 cost studies (Exhs. 75 and 75–A) he had employed a liquids leg consisting of "*all* crude oil only" leases; whereas in his latest 1955 cost study (Exh. 75–B) and in his 1957 studies (Exhs. 150 and 180) he had switched to a liquid leg consisting of only the "crude only-pumping-nil gas/oil ratio" leases. In this connection, Tidewater refers to Kahn's Exhibit 75–B relative cost allocation as

> . . . utilizing imputing factors which were, *after an earlier abortive attempt*, obtained from leases classified as gas only and crude only-pumping-nil gas/oil ratio. (initial brief, p. 22; emphasis supplied)

The facts are as follows. Although Kahn used "all crude oil only" leases as his liquid leg in his original Exhibit 75, he there explained:

> In the hope of obtaining a more reliable estimate of the cost of producing crude oil *in the absence of gas*, we requested Tidewater to furnish us on-lease expense data for those crude oil-only leases representing oil wells actually and entirely on the pump, as a separate group and for those producing though not selling any gas, as a distinct group. *However, our request for such a breakdown was not successful.* (10:1668–69; July 29, 1957; emphasis supplied)

At a later hearing session on April 10, 1958, Tidewater counsel, in the course of his cross-examination of Doctor Kahn, presented and identified (for use in connection with his interrogation) an Exh. 116. This exhibit, among other things, provided the information which had previously been requested by Kahn, showing the breakdown of the "all crude oil only" leases into those entirely on the pump. (25:3868) At a subsequent session Kahn presented his Exh. 75–B, constituting a revised 1955 cost study. He then explained, among other things, that as a result of the breakdown provided in Tidewater's Exh. 116, he had been enabled for the first time in his Exh. 75–B to develop a liquid leg composed only of the "crude only-pumping-nil gas/oil ratio" leases. (31:4713) He explained:

> You will recall that the purpose of this analysis of on-lease expenses in the crude-oil only category was to obtain an indication, from the Company's own experience, of the cost of producing oil in the comparative absence of gas. As I indicated on pp. 1667 to 1668 of my original testimony, the crude oil-only expense data I originally used provided an only imperfect measure, because they embraced a mixture of leases producing a wide variation of quantities of gas per barrel of oil. The breakdown supplied me by the Tidewater Company, showing gas: oil ratios lease-by-lease, permit a much closer approximation to what I was seeking. (31:4716–17)

He subsequently emloyed the same technique in his 1957 cost studies. (45:6773)

The record thus plainly establishes that Kahn, from the very beginning, desired and sought to obtain a breakdown of the "crude oil only" leases, which

would enable him to develop a liquid leg composed only of those crude oil leases which were entirely on the pump; and that his use of "all crude oil only" leases in his cost studies prior to Exhibit 75–B resulted solely from the fact that the intervenors' earlier requests to Tidewater for the necessary data permitting this breakdown had proved unsuccessful. Under these circumstances, it hardly seems appropriate for Tidewater to now cite this change in Kahn's liquid leg as a "flagrant example of the Intervenors' vacillation", or to characterize Kahn's earliest liquid leg as "an earlier abortive attempt."

In making an evaluation on the merits of Kahn's "crude only-pumping-nil gas/oil ratio" sample, it is important to bear in mind that

> the basic rationale of the relative cost method is to divide the joint costs of multiple purpose investment in proportion to the costs of providing the several *single* services. (31:4735; emphasis supplied)

It seem axiomatic that in developing the relative cost factor to be employed for liquids, our object should be to construct a liquid sample which, as closely as possible, will measure the cost of producing liquids in the near or complete absence of gas, so that such factor will be unaffected and uncomplicated by any lifting contribution made by gas. The "crude only-pumping-nil gas/oil ratio" sample employed here by Kahn seems clearly more suited to this objective than the "all crude only leases" sample, in view of the fact that although leases in this broad latter category show no gas *sales*, many of them nevertheless had gas *production* which *did* perform a lifting function for the liquids.

Tidewater states that the Commission in its *Phillips* decision characterized the alleged benefit of gas in the lifting of liquids as "speculative", and concludes:

> . . . it is little wonder that in *Phillips*, the Commission used *all* of the leases in the '100 percent oil' category and did not attempt to restrict its lease sample to wells on the pump and/or those which had 'nil gas/oil ratios'. (reply brief, p. 7; initial brief, p. 50)

However, this does not accurately reflect the Commission's holding in *Phillips*. It is true that the Commission there stated:

> In fact, we think that it would be almost impossible to *compute* the value of the lifting effect of gas in oil production." (Op. 338, p. 555; emphasis supplied)

As earlier noted in the instant decision, this conclusion was arrived at by the Commission in the face of the record made in that proceeding, which admittedly provided no adequate basis for computing the credit to be applied to gas for the lifting function. However, the Commission did not in its *Phillips* decision find that the benefit conferred by gas in the lifting of liquids was dubious or speculative. Instead, the Commission there stated:

> Testimony in the record showed that gas enables the recovery of a greater amount of oil from a pool than would otherwise be possible. It does this by reducing surface tension, viscosity, and specific gravity and by providing a source of energy which moves the oil through the formation to the well bore and thence to the surface of the ground. (Op. 338, p. 555)

It was because of the very difficulties encountered in the *Phillips* case in measuring and computing the precise credit which should be assigned to gas for its lifting function, that intervenor witness Kahn in the instant Tidewater proceeding developed his "crude only-pumping-nil gas/oil ratio" sample—so that this particular problem or complication would not be involved. This appears to be a practical and useful way to deal with this troublesome problem.

No such proposal or suggestion was advanced in the *Phillips* proceeding, and it therefore was not possible to work out a useful solution in that case. That historical fact, however, should not now be treated as a basis for foreclosing the Commission from further studying this matter and evolving improvements thereon.

It is accordingly concluded that the Kahn liquid sample should be evaluated here on its merits, and on that basis it is found suitable, and appropriate for use in the instant proceeding.

In the course of its attack on the liquid leg as here developed by Kahn, Tidewater notes (initial brief, p. 50) that although the "all crude only leases" category accounted for 19.77% of its total 1957 liquid production (Exh. 150, Sched. 1), the "crude only-pumping-nil gas/oil ratio" sample employed by Kahn accounted for less than 1% of its total 1957 liquid production (Exh. 150, Sched. 1 and 3). Kahn himself pointed out, in the course of his direct testimony with respect to his Exh. 75–B, that the "crude only-pumping-nil gas/oil ratio" category in 1955 comprised only 20 leases, producing 468,000 barrels of oil and $1,419,000 of revenue, representing only from 2.4% to 2.6% of the total crude oil production of the Southern and Central Divisions. (31:4717) Using this sample in Exh. 75–B he derived a "total on-lease expense" figure of $1.542, as his cost of producing crude oil in the absence of gas—this being the liquids cost factor which he then imputed to the liquids on the joint product leases. When asked whether he regarded the number of these leases and the total of their production as sufficient to provide a reliable leg for this purpose, Kahn stated:

> It would of course be preferable to have a larger sample. . . . More important, both logic and the figures themselves strongly support the reasonableness of the $1.542 figure. As my testimony indicated, one would expect oil produced in the complete absence of gas to involve higher on-lease expenses than oil produced with gas, and that is what the figures indicate. On-lease expenses of all pumping wells, excluding the cost of developmental dry holes, were $1.205, in contrast with the comparable figure of $1.542 for pumping wells with no gas. Again, one would expect the unit expense of pumping wells, which, according to the Tidewater information, produced on the average about 400 cubic feet of gas for every barrel of oil, to exceed those of wells not on the pump, which had a 2,400 average gas/oil ratio. And, in fact, oil cost only $0.90 a barrel on the latter leases, again excluding developmental dry holes, which are really in the nature of capital costs even though customarily charged to expense in the year in which they are incurred. (31:4718)

In his 1957 cost study (Exh. 150) Kahn again employed the "crude only-pumping-nil gas/oil ratio" category for his liquid leg. He noted that this sample for the year 1957 was even smaller than had been the case in 1955, but he concluded that the sample was nevertheless adequate, stating:

> You will note from line 8 of that schedule that the production on such leases now amounts to only about ¾ of one per cent of the total crude oil production of the Southern and Central Divisions; this raises a question of whether the sample is adequate. I have satisfied myself that it is, and that the figure of $1.572 per barrel it yields is a correct one for the following reasons: (a) The figure differs by only three cents from that $1.542 that I obtained from the comparable sample of leases in 1955—see Exhibit 75–B, Schedule 4, line 3—a sample that accounted for 2.42 per cent of total production; (b) the average expense per barrel on all leases in the crude-only category, which accounts for 23.7 per cent of total production,

> is, as one would anticipate, somewhat lower, $1.403—I ignore here any costs associated with incidental gas sales from these leases—and (c) the expenses of all crude-only leases *excluding those showing what Mr. Joseph refers to as incidental sales of gas* amount to $1.568, almost the identical figures; and that group had production of 3,812,000 barrels, or about 20 per cent of the total output of the Southern and Central Divisions. (45:6773–74; emphasis supplied)

Tidewater further attacks Kahn's "liquid leg" on the ground that the particular leases in his "crude only-pumping-nil gas/oil ratio" sample are among the oldest and least profitable (highest cost) leases in Tidewater's total operations"; that accordingly "the use of the operating costs obtained from this antiquated sample group . . . results in an unrealistic shift of costs to liquids." In order to demonstrate this point, Tidewater contends that Kahn's 1957 cost-of-service reflects a cost of $4.32 per barrel "for liquids produced from the more recently developed *gas-condensate* leases, and a cost of $4.51 per barrel for the year 1955." The Tidewater brief then goes on to state:

> "When the Intervenors' cost of service witness was confronted with the fact of this absurdly high cost for liquids, his only defense was that he was interested in the cost of gas and not in the cost of liquids." (initial brief, pp. 50–51)

This statement represents an inaccurate characterization of Kahn's answer to this problem, which he discussed at great length during the course of a cross-examination by Tidewater counsel running from 48:6942–7008.

It is important at the outset to bear in mind that this entire point as made by Tidewater relates to the allocated cost which would allegedly (under Tidewater's own computation in its excluded Exhs. 159 and 160) be attributed to the *condensate* produced by the gas-condensate leases, as a result of applying Kahn's relative cost method. Kahn's basic answer to this point was as follows:

(1) He emphasized that the really significant question here was whether under his relative cost method an appropriate proportion of the joint costs was allocated to *gas* on the one hand, as distinguished from *all non-regulated portions of the business* on the other (*including both crude oil and condensate*). He concluded that on the basis of the various "checks" which he had made he was satisfied that, in a general way, there was no difficulty on *this* basic, significant ground. (48:6987)

(2) He expressed serious doubts as to the meaningfulness "of trying to determine an average total cost all the way up and down the line *for condensate alone*, "which he characterized as a by-product of gas. (48:7000) He did not deny that if the same methods were used to ascertain a cost-of-service *for condensate* as he had used for gas, the results would be similar to those computed by Tidewater. However, he stated:

> But I am uncertain about what happens when you move off the lease and try to obtain costs for the condensate or natural gas liquids part of the business.
>
> And of course you will recognize that it is the off lease expenses which are the major portion of this total expenses that you got of six and a half or seven million dollars, or whatever it was. It is primarily the off lease. (48:6988)

Kahn referred to testimony by intervener witness Botset that it would be impossible in most cases to produce the liquids from the gas-condensate wells if it were not for the presence of the gas itself. Under the circumstances, he raised a question as to what was the point of

. . . trying to say independently, what is the full average total cost of producing those liquids which are incidentally brought up by the gas? (48:6989)

* * * * * * *

. . . I can't see much point in taking this byproduct, the liquids, and sort of cutting a slice through the costs all the way up to the president of the Tidewater Oil Company and saying, 'Let's put this all down on this column'. (48:6990)

* * * * * * *

But I am trying to keep a certain sense of proportion about its meaningfulness, and it is on that score, for the reasons that I have indicated, that I have some skepticism. (48:5990–91)

Tidewater counsel finally posed the direct problem as follows:

Doctor Kahn, assuming that your cost of service for the year 1955 shows that the cost of crude is two dollars a barrel and the cost of condensate is four dollars and fifty cents a barrel, does that fact, or would that fact, in your mind, raise serious doubt as to the validity of your cost of service determination? (48:6994)

Kahn replied:

It does give me pause, but as I look at my cost of service, and the critical question as I see it and I have posed it several times is gas being attributed a fair or reasonable or in some sense adequate share of total cost *as compared with the nonregulated part of the business*, basically that seems to me the appropriate test.

Now, obviously if the test that you suggest is the appropriate test, I would have real questions about it. But it seems to me that we do have to keep a certain sense of proportion about what this company's business is. And if you do show on the 1.8 million barrels of condensate production a result which seems, to put it mildly, anomalous, it seems to me the more significant question is, what result does it show on the 19.3 million barrels of liquids—of oil—or, if you will, the 21.0 million barrels of all liquids, because that is the basic distribution. And while I concede that I must think about this, and I think about it more, so far as I can see, if I decide whether or not my cost of service is basically sound or not by the test that you are mentioning, I must emphasize the extent to which you are picking out the 1.8 million barrels and leaving out the 19.3 million barrels. (48:6995–96; emphasis supplied).[22]

* * * * * * *

Now, as for this question, in the light of the overriding question, which is the reasonableness of the costs imposed on gas on the one hand and the other part of the business on the other, I cannot believe that a continued consideration of the fact presented to me today . . . would produce a basically different cost of service.

Please notice what this means. . . .

* * * * * * *

. . . if crude oil alone earned twenty-eight percent on its investment—and this is by far the more important part of the business—it certainly suggests to me that I can hardly be accused of having by my methods produced a result which puts too much of the costs on the nonregulated part of the business.

[22] Kahn noted in this connection that Tidewater's 1955 revenues from crude oil were $54.5 million, while its condensate revenue amounted to only $3.9 million. (48:7001)

> I do concede that to the extent that it is appropriate to cut this line up and down—and I have suggested that I am not sure that it is—that on this much, much smaller portion of the business, it does look as though too high a percentage of costs has been put on it.
>
> But in evaluating whether this would cause me, Hamlet-like, to make a major change in the results that I have achieved, I would emphasize these two concluding points, which induce me to say that I very much doubt that it would.
>
> First, the fact that this is so much less important than the other, and that when we put them both together by this same test that these people are applying, it comes out intelligently; and secondly, that I have serious doubts of the kind that I have just mentioned about the meaningfulness of trying to determine an average total cost all the way up and down the line for condensate alone, which is a by-product of gas. (48:6999–7000)

It is concluded that Kahn's analysis of the problem, as set forth above, represents an effective answer to this Tidewater position, and the Tidewater contention that the use of Kahn's "crude only-pumping-nil gas/oil ratio" sample results in "an unrealistic shift of costs to liquids" is found to be without merit.

Tidewater counsel made a further attempt, during the hearing, to discredit Kahn's liquid leg for 1957, by calling attention to the fact that Kahn did not use the identical "crude only-pumping-nil gas/oil ratio" leases for his 1957 sample which he had used in his 1955 sample—citing four Illinois leases which were particularly *low cost* leases, which *allegedly* met Kahn's standards for the "crude only-pumping-nil gas/oil ratio" category, but which nevertheless were dropped from his 1957 sample, although they had been included in his 1955 sample. The inference left on the record was that Kahn might have elected to omit these particular leases from his 1957 study because they would have had a downward impact upon the unit cost derived for oil under his relative cost method. (48:7030-34)

The Presiding Examiner then expressed his unwillingness to leave the record in this uncertain state, called attention to the fact that the information as to whether these particular leases *did* in fact meet Kahn's own standards for his "crude only-pumping-nil gas/oil ratio" category was peculiarly within the exclusive possession of Tidewater itself, and accordingly requested Tidewater counsel to check with his staff in the hearing room so that the precise facts might be put into the record. Tidewater counsel thereupon replied:

> After conferring with the Tidewater people here at the table, it appears that nobody is qualified to testify one way or another about that. (48:7035)

The Presiding Examiner then stated:

> Well, we will be in session later in the week, and I would suggest that you get some more precise information, and when you have the information to your satisfaction, maybe you can get it on the record.
>
> MR. ATTWELL: All right. Fine. (48:7037)

At the next day's session, however, intervenor counsel called attention to the fact that on July 28, 1959 Tidewater itself had addressed a letter to the intervenors which set forth a listing of gas-oil ratios on pumping only leases; that the data therein set forth with respect to these four particular Illinois leases made it perfectly clear that they did *not* fall within Kahn's definition of his "crude only-pumping-nil gas/oil ratio" category. (49:7051–52) In spite of this disclosure, Tidewater counsel made no effort to withdraw his charge,

but on the contrary suggested that Tidewater might possibly have inadvertently erred in its listing of the gas/oil ratios for these 4 Illinois leases in its July 28, 1959 letter; that those leases might actually (contrary to the information set forth in Tidewater's own letter) have had a very low gas/oil ratio, and that he would like the opportunity to check into the matter further. (49:7052–54) The Presiding Examiner then commented upon the entire situation as follows:

> . . . what happened yesterday left the impression that in the view of Tidewater Oil Company, based on the information you had, Dr. Kahn had not even been consistent with his own standards.
> It turns out now that we have one of two possible alternatives. It may either turn out that you were in error yesterday in the sense that the information which you gave the interveners at their request on those four leases may have been correct information and that, therefore, you were in error yesterday in suggesting that Dr. Kahn did not consistently follow his own standards.
> Or, the only other alternative that I can see is that when Tidewater Oil Company provided the requested information to the interveners sometime ago they gave the interveners the wrong information.
> The only reason I am making this comment, Mr. Attwell, is that it seems to me that since, as I stressed yesterday on the record, this information is all peculiarly within the sole possession and knowledge of Tidewater Oil Company and nobody else, I would be much disturbed to find that through the lack of care in providing information to staff or interveners in response to their request a situation might have been created in which it should now become necessary to go through other steps to modify studies which were made in good faith upon the basis of information requested of the company.
> That is the only comment I can—I am going to make about it now.
> All right.
> MR. ATTWELL: I presume there is no response necessary to that.
> PRESIDING EXAMINER: No.
> (49:7054–56)

Curiously, this matter was not thereafter raised or referred to in any way by Tidewater during the remainder of the hearing, and no reference is made to this point in the Tidewater briefs.

The District 16–3 Leases and Kahn's Shift to Recent Vintage Leases for Allocation of Net Investment

It has already been noted at an earlier point in this decision that Kahn did not include certain District 16–3 leases in his gas leg in his Exh. 150 cost study; that subsequently, during the latter stage of the hearing, when Tidewater for the first time made available certain information showing how the depreciation and depletion charges could be distributed to those particular leases, Kahn prepared and presented a new 1957 cost study, Exh. 180, in which the District 16–3 leases were added to his gas sample. He at the same time explained that it was no longer satisfactory or meaningful, under those circumstances, to use "all vintage" leases for the relative cost allocation of on-lease net investment, as he had done in Exh. 150; that he had accordingly switched in Exh. 180 to the use of "recent vintage" leases in the 1950-57 age group for that particular allocation.[22]

[22] Kahn's rationale for this change will be explained more fully at a later point.

In discussing this change Tidewater states:

> For example, when confronted with the fact that the sample set of 'preponderantly gas' leases used in their initial 1957 cost of service presentation (Exhibit 150) did not contain certain important leases in the Hollywood Field, though such leases met the definition and standards which the Intervenors themselves had established, their cost of service witness stated that a change in the 'gas leg' would also require a change in the 'liquid leg'. (initial brief, p. 49)

Tidewater then quotes the following colloquy between the Presiding Examiner and Kahn:

> Q. (By Presiding Examiner): Do I understand, Dr. Kahn, that what you are saying here is that if the District 16–3 leases are in fact to be now included in your gas leg for the purpose of your relative cost method of allocation of rate base, that you woud feel it necessary for the reasons which you have now summarized to modify the gas leg in correcting that allocation to shift from the use of the all vintage leases which you in fact used in that 1957 study to the use now of recent vintage leases and that the purpose of Exhibits 178 and 179 is to put into the record the data which would make it possible to make that change?
>
> THE WITNESS (Dr. Kahn): That is right, with the addition that I would have to make a corresponding change in the crude oil category and one of the exhibits contains that necessary information as well. I just don't want to be precluded from using this new information as my judgment dictates and as I would have been free to do so had I had it when I originally prepared my 1957 presentation. (52:7438–39)

Tidewater then characterized this colloquy as follows:

> In short, when the error in the 'gas leg' was disclosed, the Intervenors' cost of service witness also revised his *judgment* concerning the 'liquid leg,' with the result that the relative cost allocation ratios became even less favorable to gas. (initial brief, p. 49)

This does not appear to be a completely accurate characterization of what occurred.

As already noted at an earlier point in this decision, it is quite unfair and inaccurate to suggest that Kahn's failure to include the District 16–3 leases in his gas sample in his Exh. 150 cost study constituted an "error" with which he was "confronted" and which was "disclosed" for the first time when he was cross-examined by Tidewater counsel. The fact is, as noted above, that Kahn himself (six months prior to this time) had called attention to the fact that the District 16–3 leases had not been included in his gas leg in Exh. 150, and had explained the omission. (Exh. 150, Sched. 4, footnote 5) The Tidewater brief also leaves an inaccurate impression when it states that Kahn testified that a change in the "gas leg" (*i.e.*, the addition of the Dist. 16–3 leases) "would also require *a change in the 'liquid leg' . . .*"; and when it further states that "when the error in the 'gas leg' was disclosed, the Intervenors' cost of service witness also *revised his judgment concerning the 'liquid leg'* . . . ." (emphasis supplied) The fact is that as a result of the addition of the District 16–3 leases to his gas sample in Exh. 180, Kahn swtched to the use of "recent vintage" leases *for both his gas leg and his liquid leg*, in connection with his relative cost allocation of on-lease net investment.[31]

[31] Tidewater itself expressly notes this fact in its reply brief, p. 10–11.

In summarizing certain changes which Kahn made in his various cost studies from time to time during the instant proceeding, Tidewater notes (initial brief, pp. 21-26) that in Kahn's 1955 cost study (Exhs. 75–B and 76–B) he had used *different* lease samples for allocating on-lease expenses than for the allocation on-lease net investment—*i.e.*, "all vintage" leases for on-lease expenses, and "recent vintage" leases of the 1950-1955 age group for on-lease net investment. Tidewater further notes that in Kahn's first 1957 cost study, Exh. 150, he used the *same* lease samples to determine the relative cost factors for the allocation of both on-lease net investment and on-lease expenses—*i.e.*, "all vintage" leases. (initial brief, p. 25, footnote 34) Tidewater finally notes that in Kahn's final 1957 cost study, Exh. 180, after adding the Dist. 16–3 leases to his dry gas sample Kahn at the same time switched again to the use of *different* lease samples for the purpose of allocating on-lease expenses and on-lease net investment—*i.e.*, employing "all vintage" leases for on-lease expenses, and "recent vintage" leases of the 1950-1957 age group for on-lease net investment. (initial brief, p. 26, footnote 36)

Tidewater cites these changes, among others, in Kahn's various cost studies as evidence to support its charge that:

> Throughout this proceeding, as their various cost of service studies were presented, the methods, principles and costing techniques were constantly changed to coincide with the subjective ideas of the Intervenors' cost of service witness. The most flagrant example of the Intervenors' vacillation was their use of continually changing samples in order to establish relative cost factors for the allocation of production expenses and investment. (initial brief, p. 21)

Finally, in its reply brief Tidewater calls attention to the fact that the Commission in its *Phillips* decision used *all* leases in the "100% oil" category for the liquid leg of its relative cost allocation of *both* direct expense and direct net investment. Tidewater therefore attacks Kahn's shift to "recent vintage" leases for his allocation of on-lease net investment in Exh. 180 as an unjustified departure from *Phillips*, stating:

> The Commission did not restrict expense lease sample to leases of 'comparable recent vintage' for any purpose, but assured itself that it had a lease sample broad enough to cover all phases of the relative cost allocation. By way of contrast, the Intervenors have arbitrarily assumed that one group of leases is appropriate for the 'liquid leg' of their relative cost allocation of direct expense but is not appropriate for the relative cost allocation of direct net investment. They do not attempt to explain this dichotomy on a factual basis, but rely solely on the subjective opinion of their cost witness to justify the use of two different liquid factors for the relative cost allocation of direct expense and direct net investment. (reply brief, pp. 7-8)

Tidewater cites the above history as evidence to support its characterization of the Kahn presentation as

> little more than an arrangement which first determines the answer and then dips into a huge volume of detail in the record for the selection of those leases which will provide the desired allocation ratios and lend some color of rational support for an answer which is inescapably arbitrary. (initial brief, p. 49)

In order to fairly evaluate this criticism, it will be helpful to summarize at this point the manner in which this problem arose and developed—and its treatment by Kahn.

It is important to bear in mind here that the technique of using "recent vintage" leases for the relative cost allocation of on-lease net investment, while adhering to the "all vintage" lease samples for the allocation of on-lease expense, was not a device which Kahn invented *after*, or to counteract the effect of, the addition of the District 16–3 leases to his gas leg in Exh. 180—which occurred during the latter stages of the hearing, in April 1960.

On the contrary, Kahn had used this very technique in his Exhs. 75–B and 76–B *1955* cost study, presented in May 1959, and had there explained the reasons for adopting that technique in great detail. He had then noted that the liquid sample employed for his Exh. 75–B allocation of on-lease expenses, consisting of 20 pumping leases with nil or negligible gas production, involved leases which were unusually far advanced in terms of their producing life; that, as a result, their annual production had declined so significantly that the original investment cost, when divided by current production, produced a *gross* investment cost per barrel which was unrealistically high; that at the same time they were depleted on the books far more than their annual production capacity had declined, with the result that their *net* investment was unrealistically low; that this resulted in a net investment cost per unit of current production which was much lower than that on some younger leases, in spite of the fact that this discrepancy did not have any particular significance for the purpose of the objective sought in the relative cost allocation. By contrast, the imputation factor *for gas* was derived from the much younger and typically far less fully depleted gas-condensate leases. The net result was that if "all vintage" leases were used for the allocation of on-lease net investment, the imputation factors derived for liquids and gas would relate to widely divergent periods of time, and would accordingly be in widely divergent degrees unrepresentative of the cost at any particular time of duplicating the services. Kahn concluded that this would be inconsistent with the basic rationale of the relative cost method, which was to divide the joint costs of the multiple purpose investment in proportion to the costs of providing the several single services—amounting in actual practice to computing the alternative justifiable expenditures for each individual product at some given point in time. He concluded that the solution to this problem of eliminating the inconsistency or non-comparability arising from the use of imputation factors of varying ages was to compare the crude oil-only leg and the gas-only leg from leases of roughly comparable and preferably recent vintage, and he accordingly derived his imputation factors in Exh. 76–B for both gas and liquids from "recent vintage" leases of the 1950-1955 age group (31:4734–38)

At the conclusion of this explanation, Kahn was asked by intervenor counsel whether a problem was not raised by his use of one group of leases for the determination of the imputation factor for on-lease expenses, and another group for the allocation of on-lease net investment. He answered as follows:

> A. I have made some checks on this possibility, and satisfied myself that no significant distortion is introduced by this procedure. First of all, please recall it is not the absolute figures that are important, but the relationship between the imputation factors for liquids on the one hand and gas on the other. Since I use leases of similar vintage for both groups of products in each application of the relative cost method, the relationship between the two imputation factors is not necessarily distorted by the fact that I used all age groups to allocate expenses and the 1950-1955 group to allocate investment. Second, I investigated the relative *expenses* of producing oil or gas on wells in the 1950-1955 group

only, and find that the oil expenses in that group are comparatively higher than those for gas. If, therefore, I had used 1950-1955 leases for both expenses and investment, the result would have been to reduce the final gas cost-of-service by about 4 mills. I do not recommend this procedure because of the thinness of the sample on which the imputation factors would in this case be based. (31:4738–39; emphasis supplied)

The next development occurred when Kahn presented his 1957 cost study, Exh. 150, in January 1960—where he employed the *same* lease samples for both on-lease expenses and on-lease investment, using "all vintage" leases in both cases. He at this time repeated his earlier comment with respect to the crude oil-only sample stating:

I have pointed out several times in my original testimony that the net investment per unit of production on the sample of crude oil-only leases is unrepresentatively low for precisely the reason that makes those leases a good indicator of the cost of lifting oil in the absence of gas. They are old and almost completely written-off on the Company's books. (45:6792)

However, he gave the following explanation as to why he had now (in Exh. 150) reverted to the use of "all vintage" leases for both on-lease expenses and on-lease investment:

. . . in the case of the 1957 figures, I found that I could without significant distortion simply use the same groups of leases for the computation of the oil-only legs as I used in the case of expenses, excluding only those showing no or negative investment.

Q. In your supplementary 1955 testimony, however, you argued at some length that the net investment figure for the crude-only leases of all vintages was unrealistically low, and the gross investment unrealistically high, and for this reason contended that it would be better to use leases of similar age. Have you changed your mind about the logic of that argument?

A. No. I believe, as before, that the $1.83 net and the $12.93 gross investment per barrel of crude oil shown in Schedule 10 are both unrealistic, the one on the low side and the other on the high side. I have already indicated at some length in my earlier testimony why this is so—*however, the important result of the selection of imputation factors is the ratio between the two, and I find that the ratio between the net investment figures of $1.83 per barrel of oil and $0.1278 per Mcf of gas*, the latter derived in Schedule 11, *a ratio of approximately 14 to 1, is sufficiently close to the ratios that would be obtained by using other categories of leases, of more recent vintage, though somewhat lower, as to justify following this simpler procedure in the present instance.* (45:6805–6806; emphasis supplied)

The next important development in this connection occurred at a hearing session in April 1960, when Tidewater counsel offered in evidence some 24 new exhibits and related explanatory testimony (Exhs. 151-175), for use in connection with his projected further cross-examination of Kahn. The Presiding Examiner excluded all of this material (47:6891), on the following grounds: (1) that a substantial portion of the new material involved an attempt by Tidewater to present 1958 data, which might have the effect of requiring new and further cost studies on the basis of a 1958 test year—and that no justification had been shown for any such step at that late stage of the proceeding; (2) that a substantial part of the new material actually was in the nature of surrebuttal, and that there was no justification for opening the door to

such further complications at this late stage of the proceeding; (3) that these unnecessary complications could be avoided, while still providing Tidewater counsel with a full and fair opportunity to complete his testing of Kahn's latest cost studies, through the vehicle of cross-examination without the use of such exhibit material. (47:6852–69)

It appeared that in one of the proposed Tidewater exhibits included in the mass of excluded material, Exh. 153, Tidewater had set forth a breakdown of the District 16–3 leases, showing the distribution of depreciation and depletion charges to those particular leases, and had on the basis of this data added the District 16–3 leases to Kahn's gas leg. [25]

During the course of his cross-examination of Kahn on the following day, Tidewater counsel squarely raised and made a substantial point of the fact that Kahn's Exh. 150 cost study had excluded the District 16–3 leases from the gas leg. (48:7037, *et seq.*) In the course of this interrogation, Kahn indicated that although he had not previously been able to include the District 16–3 leases for the reason that the Tidewater books failed to show how the depreciation and depletion charges could be distributed among those leases, this situation could now be remedied on the basis provided in Tidewater's excluded Exh. 153, if there was also provided the data showing the estimated reserves under each of these leases and the remaining net investment for each. Tidewater counsel then explained that any additional data required for this purpose would be found in the work papers underlying the said exhibit. (48:7040–41)

In order to resolve this problem once and for all on the record, the Presiding Examiner requested Kahn and the intervenors to check into the matter further and to make a final determination, on that basis, as to whether it would be desirable and important to now add the District 16–3 leases to the gas leg in Kahn's 1957 cost study. Kahn expressed his willingness to do this. However, he called attention to the fact that at the time of his Exh. 150 testimony he had noted that the net investment figure for the "all vintage" crude-only leases was unrealistically low, and the gross investment was unrealistically high, and that he had then indicated his preference *as a matter of principle* for the use of oil and gas leases of comparable and recent vintage; that, however, the important result of the selection of imputation factors was the *ratio* between the two; that although the net investment for the "all vintage" crude-only leases in Exh. 150 was very low, the gas net investment figure seemed to be low too; that this had resulted in a ratio of approximately 14 to 1, between the oil and gas net investment figures in Exh. 150, using "all vintage" leases; that although the 14 to 1 ratio was somewhat low, he had concluded at the time that it was sufficiently close to the ratios that would be obtained by using other categories of leases of more recent vintage, to justify, *on a purely pragmatic basis*, the simpler procedure for Exh. 150 of using the same "all vintage" leases for net investment as for on-lease expense.

Kahn pointed out, however, that the Dist. 16–3 leases were all of recent vintage, being of 1950 or later vintage; that if they were now added to his Exh. 150 gas leg, the result would be to produce a substantially lower ratio between the oil and gas net investment figures, amounting to around 10 to 1, which was far out of line and unrepresentative; that the result would be to completely vitiate the circumstances which had made it appropriate in Exh. 150, on a purely pragmatic basis, to rest upon the use of "all vintage" leases for the net investment allocation. He accordingly stressed that if the Dist.

[25] This information still did not appear upon the Tidewater books, but was provided only, and for the first time, in the above-mentioned proposed Tidewater Exh. 153. (48:7046–49)

16–3 leases were now to be included, it would become logical and imperative to further adjust Exh. 150 to use gas and oil leases of comparable vintage for net investment—*i.e.*, to use gas and oil leases of "recent vintage" only. (49:7093–95)

As a result of these further developments, Kahn subsequently prepared and presented his final 1957 cost study, Exh. 180, in which the Dist. 16–3 leases were added to his gas leg, and in which he accordingly switched back to the use of "recent vintage" leases for on-lease net investment, while continuing to use "all vintage" leases for his allocation of on-lease expense. At this time he summarized his entire position on this matter as follows:

> Q. What changes were required in the allocation of on-lease investment?
> A. The leases in the 16–3 district are all of recent vintage. Since the production of those that now fall into our preponderantly gas-producing category exceeds the entire production of all leases included in that category in Exhibit 150, the effect of introducing these important new leases is greatly to increase the net investment cost per Mcf of gas. In Exhibit 150, I used for my oil and gas legs leases of all ages. Both groups, composed for the most part of old and heavily depleted leases, produced very low per unit costs unrepresentative of the current investment cost of a barrel or an Mcf of current production capacity because both suffered from the same infirmity; together they produced a ratio which I found usable. The addition of the 16–3 leases makes the gas leg far younger and far less depleted than the oil leg, and consequently produces an unrealistic ratio between them. I therefore turn to producing leases in the 1950-57 age group only.
>
> * * * * * * *
>
> Q. How does the ratio between your present oil and gas net investment legs compare with the ratio used previously in your testimony?
> A. The ratio embodied in the present, revised 1957 presentation, incorporating the very important and low-cost 16–3 leases is 22 to 1. The ratio in my recommended 1955 cost of service was 26 to 1, and in my original 1957 cost of service presentation, 14 to 1.
>
> * * * * * * *
>
> Q. Do you recommend the present allocated cost of service as superior to the earlier one?
> A. Yes, without qualification. It differs for two reasons only—first, because it incorporates the important, additional information supplied me by Tidewater, and, second, because it employs the rate base allocation method which I have already maintained is conceptually superior to the ones I actually employed in the original 1957 presentation. (53:7486–88)

Kahn also provided a final summary of his position as to the propriety of employing different lease samples for the allocations of on-lease expense and on-lease net investment in the following colloquy with Tidewater counsel:

> Q. Now, in computing your on-lease expense ratios, I believe you use leases of all ages.
> A. For expenses purposes.
>
> * * * * * * *
>
> Q. And you used leases of recent vintage for investment purposes?
> A. That is right.
> Q. Do you think there is any inconsistency of this application of the ratios, Dr. Kahn?
> A. No; I do not.

Q. Why not?

A. Well, I have explained that at extraordinary lengths, Mr. Attwell, both in my revised 1955 presentation in which I followed precisely the same procedure, and in my cross examination when several times I indicated why I felt such a procedure should be used.

Essentially, as I pointed out both those times, I felt that the leases of all age categories were not unrepresentative here of what the relative cost method called for so far as expenses were concerned, but were grossly distorted for the purposes of ascertaining net investment imputation values. (54:7496–97)

It is concluded here that it was desirable and appropriate to add the Dist. 16–3 leases to the gas leg in Kahn's 1957 cost study. It is further concluded that it was necessary and proper, for the reasons set forth at length in Kahn's testimony, to employ "recent vintage" leases for both the liquid leg and the gas leg in connection with the relative cost allocation of on-lease net investment, as was done in Exh. 180; and that the use of different lease samples for the allocations of on-lease expense and on-lease net investment was not improper or undesirable under the circumstances. It is finally concluded that the shifts which occurred in Kahn's treatment of this matter in his 1955 and 1957 cost studies were quite understandable under the circumstances as outlined above, and that there is no valid basis for the Tidewater charge that these changes were made merely "to coincide with the subjective ideas of the Intervenors' cost of service witness".

Indirect Expense and Indirect Net Investment

In allocating indirect expense (off-lease expense) and indirect net investment (off-lease investment) under the relative cost method, both Tidewater and the Staff applied the same allocation factors which had been derived for direct expense and direct net investment. Staff describes this procedure as following ". . . the Commission preference for allocating other production expenses on the same basis as direct production expenses . . .". (initial brief, pp. 13-14)

Intervenor witness Kahn, however, used a conglomerate average method under which off-lease production expense, other than regulatory expense and gas processing plant expense, was allocated to gas by use of the average (12.43%) of the following percentages:

(1) Per cent of on-lease expense other than depreciation and depletion expenses allocated to gas (3.35%);

(2) Per cent of total on-lease net investment allocated to gas (23.43%); and

(3) Per cent of total on-lease gross investment allocated to gas (10.52%). (Exh. 150, Sched. 7)

Similarly, off-lease net investment, other than gas processing plant investment, was allocated to gas on the basis of the average (16.98%) of the following percentages:

(1) Per cent of on-lease net investment allocated to gas (23.43%); and

(2) Per cent of on-lease gross investment allocated to gas (10.52%). (Exh. 150, Sched. 13)

Tidewater attacks this intervenor procedure as an unwarranted departure from the allocation methods used by the Commission in *Phillips*. (reply brief, p. 12)

Actually, the method here employed by Tidewater and the Staff is itself not precisely identical with that used in *Phillips*, where a totally separate relative cost allocation was made of indirect expense, constructing and applying totally different allocation factors than were used for direct expenses. The only discussion with respect to the indirect expenses in the Commission's

Phillips decision occurs at pp. 553-555 of Op. 338. In there holding that the distribution should have been made "on the basis of direct operating expenses," the Commission was referring to a preliminary step under the relative cost method—involving the distribution as between 100 per cent oil leases and joint product leases of that portion of indirect expenses allocated to Phillips' Oil and Gas Production Department. It therefore appears that even the method advocated in the instant proceeding by both Tidewater and the Staff for the allocation of indirect expenses represents some departure from the procedure which was followed in *Phillips*.

Intervenor witness Kahn explained his rationale for allocating indirect expense on the basis of conglomerate averages as follows:

> Q How do you support the application of the composite percentage to which you have just referred to the other two major off-lease expenses, general and administrative, and other operating expenses, general and administrative, and other operating expenses and taxes?
>
> A The answer to your question is really quite simple. What we have under these two headings is a great conglomeration of expenses, of an extraordinary variety. The two largest items in the second category, for example, are employee benefits, amounting to $683,000, and an item entitled "Profit and Loss on Property Retirement—Net" of $684,845. Other large items are "Overhead—Production Department", city, county and state property taxes, insurance, and so on. Some of these, it seems, are most closely related to the current value of property, and ought therefore to be allocated on the basis of net investment—among these I would be inclined to place insurance, property taxes, and possibly storm damage. Others, it seems to me, are more appropriately related to on-lease expenses, particularly if we exclude from the latter depreciation and depletion: among these I would be inclined to classify overhead of the production department, cash discounts, to the extent that they reflect supplies purchased on the lease, and that portion of employee benefits that is related to labor on the lease.
>
> A few other items are probably most appropriately related to gross investment—for example, "Inventory Adjustment—Material and Supplies," since we allocate working capital, material and supplies, on that basis, and possibly, again, the overhead of the production department, on the ground that the amount of effort directed toward managing producing leases is more clearly related to the gross investment than to the extent to which they may be depleted. Finally, I would suppose that gross production taxes and Federal and State excise taxes are best allocated in proportion to sales realization.
>
> Q How is one to weigh these rather complicated considerations?
>
> A I believe it is necessary to retain a certain sense of proportion here. First of all, I think it would be unnecessarily complicated to try to allocate each one of these subentries individually by the formula that seems most appropriate to it. Second, the two extreme allocation bases are on-lease net investment, which would by my allocations place 23.4 per cent on gas, and on-lease expenses excluding depreciation and depletion, which would give it only 3.35 per cent. I believe we can quickly reject both of these two extremes as possible allocation formulae. To use the first, net investment, would imply that it somehow requires less management, less general and administrative expense and other indirect expenses, to run relatively old, depleted, or indeed over-depleted leases than the less old and depleted ones; it seems to me that this is clearly not necessarily true, and may

indeed be the very opposite of the truth. On the other hand, while, as I argued in my original testimony, there is a certain persuasiveness in a regulatory proceeding giving gas and oil the same percentage markups above direct cost, it is clear that many of these indirect expenses would seem to vary more closely with gross or net investment, or sales realizations, than with on-lease expenses. For these various reasons, I think by all means the most reasonable procedure is to average these allocation formulae, as I have done.

Q Did you make any attempt to see whether the resultant average bore any close relationship to such allocations as would have been produced had you attempted to take up the individual sub-categories of these indirect expenses one by one, allocating each on what seemed to you the most plausible basis?

A I have, and it was because the results of that effort came so very close to the simple average of these allocation bases that I decided for simplicity to use the latter. (45:6797-6800)

Similar considerations induced Kahn to use conglomerate averages in his allocation of indirect net investment. (45:6809-10)

It is concluded that the Kahn method makes sense under the circumstances of the instant case, and it is hereby approved. [36]

Conclusions With Respect to the Relative Cost Allocation of Joint Production Costs

In evaluating, finally, the general validity or usefulness of the relative cost allocation method, in all its aspects, as here applied by intervenor witness Kahn, all parties agree that the results are to be assessed in the light of the fundamental principle underlying the relative cost method—*i.e.*, that both of the joint products should share whatever efficiency and reduction in costs may be reflected in the joint product operation.

In this connection, intervenor witness Kahn pointed out that the ultimate effect of his relative cost allocation was to produce a reduction of 52 percent for the cost of liquids produced from joint product leases, as compared with the cost for liquids produced from the single product leases—whereas the cost derived for gas produced from the joint product leases was 47½ percent less than that for the single product leases. Kahn noted that the resultant reductions for both liquids and gas were thus of a similar order of magnitude, and that in fact under his method the liquids showed a slightly greater benefit in cost savings from the joint production operation than was true for gas.

Tidewater counsel, however, insisted that the comparison should be made between gas on the one hand, and *natural gas liquids (or condensate) only*—and not with the broader category of *all* liquids. If the comparison is made on this basis, it shows that Kahn's method results in a cost of *condensate alone* from the joint product leases which was 38 per cent lower than the cost factor used for *all liquids* produced from single product leases, whereas the cost derived for gas produced from joint product leases was 44 percent lower than that produced from single product leases. On the basis of this particular comparison, Tidewater counsel suggested that Kahn had assigned a greater reduction in cost for gas than for liquids.

[36] It should be noted that the net dollar difference which may be attributed directly to the difference between these two approaches is actually not significant. The substantially higher level of the allocation ratio derived for gas under the Tidewater method is attributable much more directly and significantly to the fact that Tidewater employs totally different gas and liquid legs than are used by Kahn, in constructing its allocation factors for direct expense and direct net investment.

However, as Kahn pointed out, it seems clear that the significant comparison to be made here, from the point of view of the regulatory process, is that between gas on the one hand and *all liquids* on the other. The comparative data relied on by Tidewater are therefore not regarded as relevant.

Furthermore, even if the comparison were in fact to be made between the figures for gas on the one hand and condensate on the other, Kahn explained that the slight disproportion or discrepancy remaining with respect to that particular category of leases was accounted for and justified by his gas volume adjustment—which has been discussed at length and approved at an earlier point in this decision. He stated:

> Third, there is a reason for that disproportion, that slight disproportion between the sixty-two percent and the sixty-six percent that you mention, and that is, as I indicated in my redirect testimony several years ago, I thought it appropriate to modify the precisely proportionate reduction in expenses imposed on both products, because I was seeking some method of giving gas credit for lifting the liquids, and that method was the one we have described of imputing the single purpose product cost to the gross or estimated gross production of gas. And then on the basis of the fact that the difference between gross and net production of gas, and the costs justly attributable to that difference, are appropriately attributable to raising the liquids, imposing on gas only a total burden equivalent to what would be appropriate to the marketed production of gas. I believe that that will account for either all or the major part of the remaining slight discrepancy that remains in this particular category of leases.
>
> Q Dr. Kahn, as I understand your explanation, it is that if you had not made the volume adjustment, to which you referred and which we will discuss more thoroughly later on, then the joint products would have shared proportionately in the cost savings—or shall I say that the difference that now exists would have been narrowed substantially; is that correct, sir?
>
> A Yes, it would be narrowed, I would assume substantially; but I have not made the computation. (50:7116-17)

At this point, having completed the analysis of the specific problems arising in connection with the intervenors' application of the relative cost method to the allocation of joint production costs, it would be useful to make a final evaluation of the grave charges made in the Tidewater briefs against the objectivity and sincerity of the cost studies presented in this proceeding by intervenor witness Kahn. Tidewater characterizes these cost studies in the following language:

> Perhaps the most objectionable feature of the Intervenor's cost of service determinations is the complete lack of objective standards. Throughout this proceeding, as their various cost of service studies were presented, the methods, principles and costing techniques were constantly changed to coincide with the subjective ideas of the Intervenors' cost of service witness. The most flagrant example of the Intervenors' vascillation was their use of continually changing samples in order to establish relative cost factors for the allocation of production expenses and investment. In short, the Intervenors' cost of service studies are permeated with so many crucial 'subjective' judgment factors that it would appear to be much simpler, and certainly more expeditious and forthright to disregard any sham mathematical computations and simply make a single subjective determination of Tidewater's cost of service per Mcf of gas. In fact,

> if the Intervenors' cost of service 'methods are to be adopted by the Commission, it will be necessary to have their cost of service witness ever present to make the necessary subjective variations. (initial brief, p. 21)
>
> * * * * * * *
>
> It is obvious from the record in this case that the Intervenors' application of the relative cost process is so permeated with subjective judgment factors, it bears little or no resemblance to what the Commission did in *Phillips*. In fact, on close examination, the entire relative cost method employed by the Intervenors appears to be nothing more than a mathematical ritual for arriving at some numerical relationship in order to arrive at a predetermined result. During the course of this proceeding, the numerical relationships used in the Intervenors' relative cost process were changed four times. In Tidewater's view, the Intervenors' failure to justify any of these changes creates grave doubt as to the objectivity, accuracy and regulatory validity of their entire relative cost process. (reply brief, p. 11)

In considering this Tidewater complaint, it is important to bear in mind the manner in which the instant case developed and proceeded. The Tidewater hearing, in its various stages, extended over a period from May 1956 to May 1960, and it was tried during a period when the Phillips case was also in process. The key problems involved, such as the problems of allocating joints costs, were difficult questions of first impression, as to which producers, the intervenors and the Staff were all feeling their way and plowing new ground. While the Tidewater proceeding was going through its various stages, the *Phillips* hearing, the *Omnibus* hearing, and other producer rate hearings were also being conducted. The situation was one in which the various parties, witnesses and counsel in the instant Tidewater proceeding were properly interested in observing and benefiting from the developments which were taking place, and from the ideas, methods and techniques which were being explored in such other proceedings. They were, of course, equally interested in reacting to and benefiting from the information and data developed during the various stages of the instant Tidewater hearing itself.

On the basis of his very extended observation of intervenor witness Kahn throughout the instant proceeding, the Presiding Examiner is impressed with the fact that Kahn at no time closed his mind to new suggestions or new approaches, and did not attempt at any time to evade problems as they arose or to pretend that they did not exist. On the contrary, he invariably sought an opportunity to give careful consideration to new problems and new material as they were presented. Thereafter, if his further study indicated the need for a change or modification in his previous approach, he unhesitatingly and frankly made such changes—explaining in detail on the record his reasons for making such changes, and their rationale.

In this connection, it is also important to note that many of the "changes" made by Kahn in the later stages of this proceeding involved situations in which he was induced to give consideration to new data which had not been made available at earlier stages of the proceeding. In some of these situations, Kahn had made it clear at the time his earliest studies were presented that he had felt compelled to adopt a given method or technique by virtue of the fact that he had not up to that time been able to obtain a certain described type of data from Tidewater—and his later modification or refinement resulted from the fact that such data had subsequently been made available. It is of the utmost importance, in this connection, to bear in mind that all of this data was peculiarly in the sole possession of Tidewater itself at all times. Under

these circumstances, the criticism directed against the intervenors in the Tidewater briefs seems quite unwarranted and misplaced.

With respect to the Tidewater charge that Kahn's application of the relative cost method bears "little or no resemblance to what the Commission did in *Phillips*, it must first be borne in mind that the Tidewater operations, of course, differ in some respects from *Phillips*. Under the circumstances, it was not possible or sensible in some instances to follow slavishly the identical technique which was employed in the *Phillips* decision. In addition, with respect to some situations the experience gained in the *Phillips* case and in the instant Tidewater proceeding indicated that a modification or refinement of the technique used in Phillips might be desirable. Here again, there was no virtue in rigidly cleaving to the precise *Phillips* method as a matter of ritual. At this stage of the regulatory process, when there is still so much to be learned with respect to the problems of producer regulation, no useful purpose would be served by rigidly closing our minds to any and all improvements or refinements of the *Phillips* techniques.

Under all the circumstances, it is here concluded that the above-quote Tidewater characterization of the cost studies presented by intervenor witness Kahn is without justification or merit, and it is accordingly rejected.

Allocation of Exploration Costs [37]

Tidewater advocates that exploration costs should be allocated between liquids and gas under the straight Btu method, based upon the relative Btu content of the test year production of these two products. Tidewater notes that the Commission in *Phillips* adopted a modified Btu method for the allocation of exploration costs, under which the Btu content of the liquids was weighted by an economic factor of four.

Tidewater contends, however, that in view of its product mix, the areas in which it operates, and the results of its exploratory activities, the economic factor of four which was used by the Commission in the *Phillips* case should be either substantially reduced or entirely eliminated for the purpose of the instant proceeding. In this connection, Tidewater points out that unlike *Phillips*, it does not conduct exploratory operations in the large, low-cost dry gas areas such as the Panhandle-Hugoton Field; that instead it has concentrated its exploratory and development operations in the deep, high-cost producing horizons of South Louisiana and the Texas Gulf Coast Areas. In addition, Tidewater lays great emphasis upon the fact that a major portion of its gas production is from gas-condensate leases, stating:

> In fact, over two-thirds of Tidewater's 1957 gas production was produced from gas-condensate reservoirs containing hydrocarbons in the gaseous form at high pressure (Exhibit 129). It is not until after the wet gas stream leaves the wellhead that the single gaseous phase is separated into liquids and gas. Thus, insofar as Tidewater's gas-condensate production is concerned, the application of an economic factor of four, which weights liquid BTU four times as heavily as gaseous BTU, is founded on the erroneous assumption that it costs more to find and replace one portion of a homogeneous reservoir and product stream than it costs to replace another portion.
>
> . . . Since there is only a single homogeneous product in the gas-condensate reservoir and at the wellhead, a process of cost allocation which

[37] It may be noted at the outset that "developmental dry hole" costs are here combined with other exploratory expenses and allocated on the same basis, following the Commission treatment in *Phillips*.

> allocates greater costs to one portion of the single gaseous form of hydrocarbons than to another portion results in serious error. Actually, the error inherent in the Commission's economic factor of four when applied to gas-condensate production is found in the assumption that the BTU content of the wet gas stream which separates into the liquid form after the production process is completed is more costly to find than the BTU content of the same wet gas stream which remains in the gaseous form. Therefore, Tidewater believes that the BTU method of allocation, without modification by any economic factor, is the only realistic and rational method of allocating joint exploration costs between the dry gas and liquid components of the single wet stream produced from its gas-condensate leases. (initial brief, pp. 54-55)

However, an examination of the considerations which led the Commission to reject the straight Btu method in its *Phillips* decision and to adopt a modified Btu method in its stead will make it clear that none of the above contentions by Tidewater have any relevance here. As already noted at an earlier point in this decision, the Commission in rejecting the straight Btu method in *Phillips* concluded that

> . . . if the Btu method is to be made practicable and useful for the allocation of costs it must be modified by the exercise of judgment based upon the facts and the principles that guide producers in the incurrence of costs. (Op. 338, p. 557)

The Commission then stressed that:

> . . . exploratory activities are directed to obtaining saleable products so that it seems reasonable that market relationships should also be reflected in the allocation. (Op. 338, p. 559)

In order to thus reflect the market relationships between liquids and gas, the Commission there developed and applied to the Btu content of the liquids an adjustment factor of four, based upon the *relative price ratio* of a barrel of petroleum to an Mcf of gas at the wellhead.

In this connection, it is important to note here (as pointed out earlier in this decision) that the Commission in the *Phillips* case applied its modified Btu method to *all* categories of leases, including gas-condensate leases, without distinction, in spite of the fact that the greatest part of *Phillips'* production from joint product leases came from gas-condensate leases. As earlier noted, Phillips' 1954 production of gas from gas-condensate leases, amounting to 78,499,506 Mcf, was substantially higher than Tidewater's 1957 gas production from gas-condensate leases, amounting to 61,695,657 Mcf. The argument made here by Tidewater to the effect that the alleged special characteristics of the gas-condensate leases require the adoption of a special and different allocation approach for the exploration costs relating to such leases, involves the same reasoning which was also used by Tidewater to justify its use of a special approach for the allocation of joint production costs relating to such leases. The defects in this argument with respect to the gas-condensate leases have been fully set forth at an earlier point in this decision in connection with the discussion of the allocation of joint production costs. The Tidewater attempt to single out the gas-condensate leases for special treatment in connection with the allocation of exploration costs is fatally defective for the same reasons, and it is hereby rejected.

In developing its theory with regard to the required special treatment of the gas-condensate leases with respect to allocation of exploration costs, Tidewater contends that the application of the Commission's *Phillips* economic

factor of four to Tidewater's gas-condensate production would be improper in that it would be "founded on the erroneous assumption that it cost more to find and replace one portion of a homogeneous reservoir and product stream than it costs to replace another portion." This argument reflects an incorrect interpretation of the Commission's purpose in applying the economic factor of four in its *Phillips* decision. It is perfectly clear from a reading of that decision that the Commission's adoption of the Btu adjustment factor of four in that case was not based upon a cost rationale at all, but rather was based upon the Commission's conclusion that in using the Btu method for the allocation of exploration costs fairness and a sense of reality required that the relative values of the liquids and gas must be reflected and given some weight in making this allocation. Under these circumstances, Tidewater's instant argument that the cost of finding the Btu content of the condensate liquid which ultimately separates out of the wet gas stream is not any different than the cost of finding the Btu content of the condensate gas, seems totally meaningless and irrelevant.[28]

In further support of its instant position, Tidewater makes an extended argument with respect to its increased costs of finding and producing gas—stressing such matters as the trend of increasing exploratory and development drilling costs, the trend of increasing operating expenses, the decreasing realization per Btu of total production resulting from the increasing role played by gas in its total production, and the like. (initial brief, pp. 55–57; reply brief, pp. 25–28) This argument overlooks the fact that all of these considerations with respect to industry trends were recognized and discussed in the greatest detail by the Commission in its *Phillips* decision (Op. 338, pp. 559-560), and constituted the basis for the Commission's refusal to adopt a sales realization method. The Commission there concluded, in this connection:

> Because of the industry tendencies that have developed, we deem it appropriate that in allocating the joint exploratory costs and development losses of Phillips, we shall give increased consideration to the Btu's in gas as a fuel as compared with oil and not confine ourselves entirely to a relationship based solely on recent historical relative values or relative production costs. (Op. 338, p. 560)

Finally in approving and adopting its economic factor of four, the Commission stated:

> The ratio we adopt to allocate Phillips' exploration costs thus gives more consideration to the relative Btu contents than does the relative test year realizations, or relative production costs, gives effect to the upward trend of gas production relative to oil in relation to the present level of exploration costs, and recognizes the increasing contribution that Phillips' current exploration costs are making to gas supplies as compared with oil. We believe that using such a ratio, and also fixing all gas rates on the basis of costs thus obtained will be of great benefit to consumers and producers alike. (Op. 338, p. 561)

Under these circumstances, the point here raised by Tidewater does not appear to be relevant, since the conditions stressed by Tidewater are already accounted for and reflected under the Commission's modified Btu method.

In view of the above, it is here concluded that Tidewater's exploration costs should be allocated between liquids and gas under the modified Btu method

[28] In addition, the argument seems particularly meaningless when it is recognized that the exploration costs which we are attempting to allocate here consist mainly of the costs of *unsuccessful* exploration.

approved by the Commission in *Phillips*. A question is presented, however, as to whether the *Phillips*-approved economic factor of four is the appropriate factor for use in the instant Tidewater proceeding.

In developing its economic factor of four in the *Phillips* case the Commission started out by noting that the ratio of the Btu content of a standard measure of gas (an Mcf) to the Btu content of a standard measure of oil (a barrel) is about 1 to 6. (Op. 338, p. 560) However, the Commission then noted that on the basis of Phillips' own prices in the field its ratio of the price of a barrel of petroleum to an Mcf of gas at the wellhead ranged from a ratio of 39 to 1 in 1952, 33 to 1 in the test year 1954, down to about 29 to 1 in 1956; that if this trend were extended, the *Phillips* price ratio would have reached 24 to 1 in 1958. The Commission further noted that on a nation-wide basis the same ratio was 32.5 to 1 in 1952 and 27 to 1 in 1954; that, on the basis of figures published by the Bureau of Mines, this trend, with certain ups and downs, had continued, reaching 25.3 to 1 in 1958; that this nation-wide trend, if extended, would have reached a ratio of around 23 to 1 in 1959. (Op. 338, p. 561) After considering this data, the Commission concluded that a price ratio of 24 to 1 should be reflected in arriving at the desired economic adjustment factor. The Commission then concluded:

> Upon the basis of the considerations expressed above, and the record in this proceeding, we are of the opinion that the proper economic factor to be applied to the straight Btu content of oil to allocate Phillips' test year exploration costs is four, so that the cost relationship of finding one Mcf of gas to one barrel of oil will be about one to 24. (Op. 338, p. 560)

In determining the economic adjustment factor to be applied in the instant proceeding, it would seem reasonable to consider and reflect the most recent price ratio data which is available. On the basis of figures published in the most recent Bureau of Mines Mineral Yearbook, it appears that the *actual* nation-wide price ratio was 22.5 to 1 for the year 1959.[29] Using the Bureau of Mines nation-wide price ratios for each year from 1952 to 1959, a trend can be plotted which would indicate an expected price ratio of approximately 22.2 in 1960 and 21.1 in 1961.[30] Although it would be of interest in this connection to determine the Tidewater price ratios for recent years on the basis of its own prices in the field, it is not possible on the instant record to determine any Tidewater price ratios beyond the test year 1957. A rough calculation would indicate that Tidewater's actual price ratio for that year was 21.64 to 1.[31]

In view of the fact that the nation-wide price ratio was down to 22.5 to 1 in 1959 and since it can be estimated that if this trend were continued the nation-wide price ratio would have reached 22.2 for 1960 and 21.1 for 1961, there might be a reasonable basis for contending that a somewhat lower economic adjustment factor should be used in the instant proceeding than the factor of four which the Commission adopted in *Phillips*. In no event, however, would it be possible on the basis of the most recent data available in this proceeding to justify an economic adjustment factor which would

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[29] The actual ratio was thus slightly lower than the 23 to 1 ratio which the Commission estimated for the year 1959 in Op. 338.

[30] Although the Bureau of Mines data was not made a part of the record in the instant proceeding, it is considered appropriate to take administrative notice of such data, as the Commission did in Op. 338.

[31] Based on Tidewater's 1957 crude oil unit realization of $3.138 per barrel (Exh. 150, Sched. 8, Footnote 2); and using the price of 14.5 cents per Mcf for gas, which is described in intervenors' initial brief (p. 32) as Tidewater's average revenue for gas sold under rate schedules in effect during the 1957 test year (derived from Tidewater's 1957 Form 301).

reflect anything lower than an 18 to 1 price ratio, which would provide the basis for an economic adjustment factor of 3. In view of the facts as outlined above, it seems clear that an adjustment factor of 3 would be on the low side and would give the benefit of all doubts to Tidewater in this connection. Under all the circumstances described above, and in view of the meager experience which the Commission has had thus far in deriving a proper Btu adjustment factor in such situations, it is concluded that an adjustment factor of three should be applied to the straight Btu content of the Tidewater liquid production, in applying the Commission's *Phillips* modified Btu method in this proceeding.

Intervenors' application of the *Phillips* modified Btu method to Tidewater's exploration costs in this proceeding is set forth in Appendix A, Table 2, of intervenors' initial brief. Tidewater contends that the intervenors erred in their application of the Btu economic adjustment factor in this computation, in that they applied the adjustment factor to the Btu content of *all* liquids produced by Tidewater—including the Btu content of liquids extracted in gas processing plants. It is pointed out, correctly, that this represents a departure from *Phillips*, where the economic adjustment factor was applied only to the Btu content of liquids produced and separated on the lease. The Commission concluded in *Phillips* that the allocation of wet gas stream costs between natural gas and extracted liquids should be made under the straight Btu method, and that in this particular step it would not be necessary to bring in the factor of market price as was done in connection with exploration costs. (Op. 338, p. 563)

The problem arises here because in Tidewater's application of the straight Btu method for its allocation of both production and exploration costs between liquids and natural gas, extracted liquids were included in the total liquids category. (Exh. 129, Sched. 5; Appendix 3 to Tidewater initial brief, Sched 2, p. 6) The net result was that Tidewater's distribution of wet gas stream costs between extracted liquids and residue gas occurred in the same step as its general allocation of all costs between total liquids and gas. Since both intervenors and Staff simply adopted these Tidewater figures, the net effect of applying the Btu adjustment factor to the Tidewater total liquids figure was to simultaneously adjust the Btu content of the extracted liquids as well.

It is concluded that in order to apply the adjustment factor in a manner consistent with the Commission's treatment of this matter in *Phillips*, a modification must be made in intervenors' application of the modified Btu method in Appendix A, Table 2 of its initial brief. This has been accomplished, as shown on Appendix A, Table 3 of the instant decision, by separating out the plant liquids from the total "liquids sales" figure shown in the intervenors' computation, and by then applying no adjustment factor at all to such plant liquids figure.

Pursuant to the conclusions reached above, the allocation of exploration and development costs under the modified Btu method is here accomplished (Appendix A, Table 3 of this decision) by using the computation in Appendix A, Table 2 of intervenors' initial brief as a point of departure, and by making two modifications therein: 1) the substitution of an economic adjustment factor of three, in place of the *Phillips* factor of four; 2) application of this adjustment factor solely to the Btu content of liquids produced and separated on the lease. The result is to produce an allocation ratio of 24.17% for gas under the modified Btu method, which is here adopted.

It is of interest to note here that intervenors' cost of service studies, Exh. 150 and 180, employed a reserves added realization method (RAR) for

their allocation of exploration costs—this method being roughly the same as the RAR method which the same intervenor group presented in the *Phillips* case, and which was there rejected by the Commission in Op. 338. The Tidewater briefs contain an extended discussion attacking the RAR allocation method, and arguing that there were in any event serious deficiencies in the manner in which it was applied in the instant proceeding.

In view of the fact that this method was rejected by the Commission in *Phillips*, no purpose would be served here by discussing intervenors' RAR method or the Tidewater objections thereto. It is of interest to note, however, that intervenors under the RAR method arrived at an allocation ratio for gas of 27.42%, which is somewhat higher than the 24.17% allocation ratio here approved under the modified Btu method.

In concluding this discussion with respect to the allocation of exploration and development costs, it is of interest to note that in spite of all the complexities which have surrounded this problem in both the *Phillips* case and the instant Tidewater proceeding, the entire question in the last analysis resolves itself down to a very simple and basic choice between two conflicting alternatives:

(1) whether to allocate exploration costs between liquids and gas under the straight Btu method, which does not in any way measure or reflect the relative values of the two products—this being a method which in the *Phillips* case would have resulted in the allocation of 61.88% of exploration costs to gas;

(2) or whether to adopt a method which *does* measure and reflect the relative values of the two products. In the *Phillips* case a number of different types of allocation methods reflecting relative values were proposed, ranging in result from the RAR method which allocated 30.46% to gas, to a low of 20.82% under a sales realization method.

The Commission in *Phillips* adopted the modified Btu method, with an economic adjustment factor of four based upon relative values—producing an allocation of 32.742% to gas. This represented only 52.9% of the ratio allocated to gas under the straight Btu method.

It is interesting to note that in the instant proceeding Tidewater's straight Btu method would allocate 49.31% of exploration and development costs to gas. By contrast, the method here approved, consisting of a modified Btu allocation with an economic adjustment factor of three, allocates 24.17% to gas—representing 49.77% of the ratio allocated to gas under the straight Btu method.

Kahn's 14,500,000 Mcf Volume Adjustment

Intervenor witness Kahn concluded that Tidewater's 1957 test year gas production was abnormally low and out-of-line with its potential productive capacity. In order, therefore, to match test year gas production with potential productive capacity he concluded that Tidewater's 1957 gas production figures should be normalized by increasing actual gas sales volumes by 14,500,000 Mcf (from 95.2 million Mcf to 109.7 million Mcf)—prior to determining Mcf unit costs for development dry holes, exploration expense, and return on gas rate base. (Exh. 150, Sched. 15)

Kahn supported this adjustment on the following grounds:

(1) There was a very much higher concentration of developmental dry hole expense in the Southern and Central Divisions in 1957 than in 1955 on essentially gas-producing properties—amounting to more than a fourfold increase. At the same time gas sales for the entire Southern and Central Divisions went

up only approximately 12½ per cent, and the increase in sales from gas-condensate leases alone amounted only to roughly 20 per cent during this two-year interval. (45:6810-11)

(2) Exploratory expenses of the Southern and Central Divisions were approximately 50 per cent higher in 1957 than in 1955. Exploratory expenses allocated to gas (under Kahn's RAR method) rose 64.5 percent during this period. (45:6811-12)

(3) In the years 1950-1952, gas wells accounted for between 4.66 and 6.75 per cent of the total net productive wells drilled by Tidewater. In 1953-1956 the ratio fluctuated within a narrow range of 10.24 and 12.78 per cent. However, in 1957 gas wells suddenly jumped to 17.05 per cent of the total. This Tidewater ratio of gas wells to total productive wells drilled substantially exceeded the industry average. (45:6815-16)

On the basis of this data Kahn concluded that Tidewater in 1957 had greatly increased the relative emphasis of its operations on gas. He further concluded that Tidewater's additional expenditures in 1957 did in fact produce a proportionately larger physical production capacity than was reflected in sales during that year. This conclusion was based upon the following:

(1) He examined the ratios between the end-of-year reserves and annual production of natural gas by the Southern and Central Divisions for 1957 and the five years preceding, and for the entire company in 1957 and 1958. These figures were as follows:

Year	*Life Index*
Southern and Central Divisions:	
1952	27.25
1953	25.71
1954	27.26
1955	27.36
1956	23.62
5 year average	26.24
1957	30.16
Entire Company:	
1957	29.30
1958 [1]	27.03

(45:6812-13)

[1] Kahn explained that he had used "entire company" figures for 1958 because he did not have data limited to the Southern and Central Divisions for that particular year. However, he concluded that this did not present a serious problem, because

> . . . I did make a comparison of the year by year changes in the production of the company and in the reserves of the company with those of the southern and central division, that is, in the preceding years for which I had data for both, and found a very, very close correlation. (52:7372)

These figures demonstrated that in none of the five years preceding 1957 was the Tidewater life index anywhere near the level reached in that later year. The life index in 1957 was in fact almost four years higher than the average for the preceding five years. Kahn concluded that this evidence provided a very clear indication that the greatly increased developmental and exploratory expenses for the test year 1957 did in fact leave the Southern and Central Divisions at the end of that year with a production capacity that would in terms of the company's experience in the preceding five years, have supported a considerably higher level of output in that year. He further concluded from the above data that the 1957 situation was obviously temporary, noting that in 1958 production moved up again to a substantial degree, dropping the life index by 2.27 years.

As a further indication that the increase in output of gas in 1957 was unusually low compared with the increase in reserves, Kahn considered the year-by-year increases, in both percentage and absolute terms, in production and proved reserves of natural gas in the Southern and Central Divisions

for the period 1952-1957, and for the entire company in 1958. This data showed the following:

Increases over the preceding year

Year	Production		Proved reserves	
	Million Mcf	Percent	Million Mcf	Percent
Southern and Central Divisions:				
1952	11	25.0	139	10.2
1953	7	12.7	95	6.3
1954	11	17.7	396	24.8
1955	13	17.8	363	18.2
1956	11	12.8	62	2.6
1957	6	6.2	852	36.0
Entire Company:				
1958	16	15.6	204	6.7

(45:6814-15)

He concluded that the extraordinary and abnormal character of Tidewater's 1957 experience was demonstrated by the extraordinarily large increase in reserves of gas on both an absolute and on a percentage basis, and by the extraordinarily small increase in production which followed.

As still further evidence that Tidewater had in being at the end of 1957 capacity capable of a higher level of production than was in fact demonstrated in that year, Kahn noted that although the company's allocated end-of-year gas rate base increased by 90 percent between 1955 and 1957, this was accompanied by only a 12.5 percent increase in the production of natural gas. (45:6817-18)

Finally, he pointed to the fact that in 1955, 35 percent of the net investment in the gas-condensate category was accounted for by non-producing leases, whereas in 1957 this ratio had risen to 51 percent. By contrast, in the crude-casinghead gas category only 2.2 percent of total net investment was accounted for by non-producing leases. (45:6818)

Kahn further concluded that the unusual character of this Tidewater experience for 1957 was not reflected in similar behaviour in the industry at large. He noted that in the years 1950-1952 gas wells accounted for between 4.66 and 6.75 percent of the total net productive wells drilled by Tidewater; that in the period 1953-1956 the ratio fluctuated within a narrow range of 10.24 and 12.78 percent; but that in 1957 gas wells suddenly jumped to 17.05 percent of the total. This substantial Tidewater increase in 1957 reflected a much higher rise than the industry average. (45:6815)

As a final comparison, he noted that in the 1951-1956 period the gross additions to the Tidewater Southern and Central Division reserves of gas averaged 9.52 Mcf per barrel of comparable gross findings of crude oil; whereas in 1957 the ratio shot up to 18.46 Mcf per barrel. By contrast, for the industry as a whole the 1951-1956 average was 5.60 Mcf per barrel, with ratios ranging from 3.64 Mcf per barrel in the former year to 8.36 in the latter year, while the 1957 industry-wide figure remained stable at 8.30 Mcf per barrel. A similar comparison of 1958 and 1957 data for the company as a whole demonstrated further that 1957 represented an unusual year. Gross findings for the entire company were 15.25 Mcf per barrel of oil in 1957 and dropped back to 6.53 Mcf in 1958. By contrast, for the country as a whole the ratios remain fairly stable at 8.30 and 7.29 in those two years. (45:6816)

On the basis of the data set forth above, Kahn concluded that Tidewater in 1957 had greatly increased the relative emphasis of its operations on gas—compared both with preceding years and with the years that followed, and

with the industry at large. He further concluded that Tidewater at the end of the year 1957 had "in being" a capacity capable of a much higher level of production than was in fact demonstrated in that year. He accordingly concluded that an upward normalization of the volumes of gas actually produced in the test year 1957 was necessary in order "to get 1957 back on a basis comparable with other years." (45: 6823); and that such a nomalized adjustment was a prerequisite to the use of 1957 as a test year for the purpose of fixing rates in the instant proceeding.

He further concluded that a reasonable procedure for making such a normalizing adjustment would be to normalize the 1957 sales of the Southern and Central Divisions upward by the amount required to produce the same life index as the five-year average of 26.24 for the preceding five years. Using this formula, he derived a normalizing gas volume adjustment in the amount of 14,500,000 Mcf.

Kahn stressed that the purpose of his normalizing adjustment was not to remove non-producing properties from the rate base; that rather its purpose was to prevent a double earning of the approved rate of return—first, by deriving a relatively high rate through the process of dividing the total dollars required by the temporarily low 1957 production level; second, through the greatly increased sales which were ready to be made by Tidewater by the end of 1957.

Kahn did not recommend that Tidewater's total cost of service should be divided by the normalized production figure. He recognized that the higher production level attained in 1958 must have been accompanied by higher expenses of certain types—for example, depreciation and depletion. He accordingly proposed that the normalized production figure should be used as the denominator in computing the per Mcf cost only in the case of those elements in the total cost of service which created the capacity and which would not in themselves require an increased expenditure in order to bring about actual production up to the production capacity which they had created. These elements constituted developmental dry hole losses, exploratory expenses, and the return on investment.

In evaluating the merits of the intervenors' proposed 14,500,000 Mcf volume adjustment it is recognized that Tidewater's costs have actually shown a rising trend, and it is for this reason that the year 1957 is here adopted as the test year. However, it is important to note that this higher level of costs in 1957 to a significant degree results from and reflects an expansion by Tidewater in its exploration and developmental operations for that year, as compared with its 1955 operations. Under these circumstances, if the year 1957 is to be appropriately acceptable as a test year, it becomes important to determine whether the production of gas in that year reflected the mentioned expansion to a degree which can be regarded as normal and representative for the Tidewater system. The data presented by intervenor witness Kahn, referred to above, clearly indicates that this was definitely not the case in the year 1957, but rather that the 1957 relationship between the expanded exploration operations and the actual production and sales of jurisdictional gas was seriously unrepresentative and out-of-line with what could be expected normally for the Tidewater system.

Under such circumstances, it is concluded that it would be clearly improper in this case to use the 1957 test-year cost of service without applying an appropriate and reasonable normalizing adjustment to Tidewater's 1957 actual jurisdictional gas production volumes. The failure to make any such normalizing adjustment would be particularly unfair in view of the fact (which will be

developed at a later point) that a 1957 *year-end* rate base is here being adopted rather than an average 1957 rate base.

The Staff's initial brief (p. 16) concludes that no such adjustment should be made in this proceeding, on the ground that it is "infected with the hazards of prediction, being based on prior years' experience". The Staff nevertheless concedes that the failure to make any such adjustment would produce an unsatisfactory result, stating:

> Nevertheless, it does appear that the 1957 exploration costs are excessive when applied wholly against unexpanded Tidewater gas production in 1957. (initial brief, p. 16)

It is concluded that the circumstances outlined above far outweigh the negative considerations advanced by the Staff and by Tidewater. It is significant that Tidewater did not at any point, either during its extremely lengthy cross-examination of Kahn with respect to this problem or in its briefs, raise any question whatsoever as to the validity of the data relied on by Kahn in support of this proposed adjustment. Instead, during his lengthy cross-examination of Kahn on this subject (52:7331-7390) Tidewater counsel raised and explored with Kahn a number of suggested possible fallacies in the rationale for his adjustment, in the use which he made of the data, and in the conclusions which he drew therefrom. An examination of this portion of the transcript indicates that Kahn effectively disposed of all of these problems.

In the course of its attack upon Kahn's instant volume adjustment, Tidewater contends that under normal and customary operating conditions producers commonly build up exploration operations and productive capacity in excess of actual production, which does not reach its full potential until some later date; that this lag between exploration operations and actual production and sale is perfectly normal (citing the Commission's discussion in *Phillips*, at pages 550 and 565); and that the approval of the instant proposed adjustment would discourage producers from investing greater sums in exploratory efforts. It is concluded, however, that by virtue of allowing Tidewater a return on year-end rate base the company is here given the benefit of that lag. However, if this maximum end-of-year investment is matched against a volume of annual production which is abnormally low and out-of-line, the result is to reflect a lag which goes far beyond the normal, representative operating situation. In here adopting the intervenors' 14,000,000 Mcf gas volume adjustment the purpose is merely to restore the picture to one reflecting a *normal representative lag*.

Allocation of Production Costs Between Residue Gas and Liquids Extracted from the Wet Gas Stream

In the *Phillips* case the Commission applied its relative cost allocation only to those liquids separated on the lease, and used the straight Btu method for the allocation of wet gas stream costs in a final and separate step between residue gas and extracted liquids.

In the instant proceeding, however, Tidewater did not make the allocation of wet gas stream costs between extracted liquids and residue gas in a separate step. Instead, in applying the straight Btu method for its allocation of production and exploration costs between the two categories of total liquids and gas, Tidewater included extracted liquids in the total liquids category (Exh. 129, Sched. 5). The net result was that Tidewater's distribution of wet gas stream costs between extracted liquids and residue gas occurred in the same step as its general allocation of all costs between total liquids and gas.

The Staff and the intervenors followed the same short-hand, one-step method However, since Staff and intervenors employed the relative cost method, rather than the Btu method, for their allocation of joint production costs, the net effect was that joint production costs were thereby allocated to extracted liquids under the relative cost method. At pp. 13-14 of its reply brief Tidewater criticizes this procedure as being a departure from the Commission method in Op. 338. It contends that the intervenors' application of the relative cost method to all liquids whether separated on the lease or at the processing plant results in an unrealistic shift of costs to liquids as demonstrated by the following comparison:

	Production and Exploration Cost per Barrel of Liquid Extracted From Wet Gas Stream Including 11% Return
"The Commission in *Phillips*	$ .4295
Tidewater's Application of Phillips (Initial Brief)	.4759
Intervenors' Application of Phillips (Initial Brief):	
Exhibit 150 method	2.627
Exhibit 180 method	2.651 "
(reply brief, p. 14)	

Unfortunately, the Tidewater brief does not indicate where these figures were obtained or how they were derived. It is important to bear in mind, however, that the comparatively low cost thus calculated by Tidewater for extracted liquids under its application of *Phillips* procedures reflects not only Tidewater's use of the separate-step Btu method for the allocation of wet gas stream costs, but also reflects its purported application of "Phillips procedures" in certain other aspects which have here been rejected—for example, its use of the *Omnibus* imputed factors in applying the relative cost allocation method.

It should also be noted that no issue was raised at any time throughout the lengthy Tidewater proceeding with respect to the proper method for handling the allocation of costs to the extracted liquids. Tidewater was aware throughout the hearing that Staff and intervenors had followed the Tidewater lead in using the short-hand one-step method for this purpose, and that this resulted in intervenors' applying their over-all relative cost allocation method to the extracted liquids, as well as to the liquids separated on the lease.

In addition, it is concluded that even if the allocation to extracted liquids were made in a separate step under the *Phillips* approach, with all other components of the cost-of-service being derived under the methods herein approved, the difference in results would not be sufficiently significant to warrant reopening this matter at this late stage. Under these circumstances, it is concluded that the objection here raised by Tidewater, which was made for the very first time in a direct and unequivocal manner in its reply brief, is not entitled to further serious consideration.

Gasoline Plant Costs

Although Tidewater included gasoline plant return and expenses in its total cost-of-service for liquids and gas (Exh. 129, Sched. 2, lines 4 and 10) it did not allocate any such gasoline plant costs to gas in its proposed cost-of-service. As pointed out by the Staff (initial brief, p. 9), Tidewater had originally assigned some of its gasoline plant costs to producing leases on its basic book accounts. The net result was that a portion of such gasoline plant costs was ultimately assigned to gas under the intervenors' relative cost allocation of production costs between liquids and gas.

Since the record does not show what portion of gasoline plant cost was assigned on Tidewater's books to "producing leases" accounts, or the method by which such assignment was made, it is not possible to determine whether this Tidewater technique accounted for all gasoline plant costs which properly should be chargeable to gas. Under these circumstances, it seems fair to simply follow Tidewater's own approach, under which there is not allocated to gas any of the costs remaining in the "gasoline and cycling" plant account.[22]

Accordingly, gasoline plant costs have been omitted in Appendix A, Tables 2 and 5 at the end of this decision, which deal with the allocation of off-lease expenses and off-lease net investment between liquids and gas.

Rate Base

In *Phillips* case the Commission used a year-end rate base for the test year, rather than an average rate base. It noted that Phillips' investment had been steadily increasing "presumably, in part, because of the increasing costs of drilling for gas". The Commission then held:

> In a company with such a rapidly expanding need for investment, we are of the opinion that the average test year rate base is not as representative of succeeding years as the year-end test year rate base, and therefore we agree with the examiner that year-end should be used. (Op. 338, p. 565)

Tidewater contends that similar considerations require the use of a year-end rate base in the instant proceeding. Although intervenor witness Kahn used an average rate base in his cost studies, he indicated during cross-examination that he did not wish to take any position on this particular question in connection with the problem of fixing rates for the future. Furthermore intervenors' initial brief, in applying to the facts of this case the allocation procedures adopted by the Commission in *Phillips*, employed a year-end rate base in place of Kahn's average rate base.

It is concluded that year-end rate base should be used here, for the same considerations which were determinative in *Phillips*.

Working Capital Allowance

Under the traditional method employed in rate proceedings involving electric companies and pipeline companies, the Commission grants an allowance for working capital which includes (1) an appropriate allowance for materials and supplies, and (2) an allowance for cash requirements representing one-eighth of annual operating expenses, or 45 days' expenses.

In *Phillips* the Commission adopted the same method in computing the working capital allowance, stating that it saw no reason why the traditional method should not also be applied for the independent producers. (Op. 338, p. 566) Tidewater, however, has employed a different technique in this proceeding, using a balance-sheet cash figure as its working capital allowance for cash requirements (Exh. 128, Sched. 2, p. 13) and allocating this amount among gasoline plant, royalties, and leases (Exh. 128, Sched. 2, p. 10). Intervenors have simply adopted this Tidewater method, without comment. (Exh. 150, Sched. 13).

It is concluded that the working capital allowance should here be derived in the traditional manner as adopted by the Commission in *Phillips*, and as employed by the Staff in Appendices A and B to its initial brief. The amount allowed for cash requirements, shown on Appendix A, Table 5 of this

[22] It is relevant to note here that this matter was similarly handled in the *Phillips* case, where Phillips "charged the investment and operating costs of the gasoline plants wholly to the liquids." (Op. 338, p. 563)

decision, is adopted from Appendix E to Staff's initial brief. The Staff allocated this allowance between liquids and gas under its general approach for the relative cost allocation of indirect investment, applying the same factor which it derived for direct investment. Since, as earlier pointed out, the intervenors' average composite ratio method has instead been adopted for the allocation of indirect investment, the working capital allowance is here allocated between liquids and gas pursuant to that method, as shown in Appendix A, Table 6 of this decision.

Rate of Return and Federal Income Tax Allowance

It is conceded that Tidewater actually incurred no income tax liability in the test year 1957 (Tidewater reply brief, p. 29). Indeed, it had a negative tax, or a tax credit in 1957 which was due, among other things, to "accelerated exploration and development activities". (Staff initial brief, p. 20)

However, Tidewater takes the position that it is entitled to a return on its investment which will compensate it for the risks inherent in its natural gas operations and provide a substantial increment of incentive for exploration and development plus compensation for the wasting assets and that

> Whether this requisite return is provided by an allowance stated as rate of return or a rate of return, plus statutory tax benefits, is immaterial to Tidewater. What is important to Tidewater is the compensation it receives for its natural gas, and not how this compensation is calculated. (initial brief, p. 81)

Consistent with this philosophy, Tidewater states that it

> relies on the testimony of Dr. Ralph E. Badger who recommended a 25% rate of return including actual Federal income tax or its equivalent of a 12% rate of return and Federal income tax computed without regard to statutory depletion and the expensing of intangible drilling costs. (initial brief, p. 67)

Tidewater states this another way in its reply brief, as follows:

> The retention of tax benefits is the *sine qua non* and the complement of an exclusive reliance of earnings price ratios. When the tax benefits are added to an earnings-price-ratio-determined return, the sum of the two does no more than meet the capital attraction test. (p. 30)

This entire Tidewater position is, of course, strongly reminiscent of the rate of return position taken by Phillips Petroleum Company in the *Phillips* proceeding. Phillips there contended that it should be allowed a 12% rate of return, plus the allowance of phantom taxes; or that, in the alternative, it should be allowed a 17-18% rate of return, plus actual taxes. The Commission, however, allowed Phillips an 11% rate of return, plus *actual* taxes—and did not treat the use of earnings-price ratios in its rate of return determination as being in any way dependent upon the allowance of the benefit of "phantom taxes" to the producer.

Tidewater relies upon the recent decision of the Court of Appeals in *El Paso Natural Gas Company* v. *F.P.C.*, 281 F. 2d 567 (CCA 5, 1960) as supporting its general position on this subject. It contends that in that decision

> . . . the court stated that the Examiner and the Commission may look to the tax benefits relating to statutory depletion and the expensing of intangible drilling costs as a measure of the incentive necessary to attract capital for exploration and development, as well as a measure of the allowance needed to cover the depletion of the wasting asset. (initial brief, pp. 76–77)

Apparently on the basis of this interpretation, Tidewater contends that the Commission's addition in the *Phillips* case (Op. 338) of a 2% increment to the 10% factor derived from earnings-price ratios, did *not* provide the required "strong incentive for exploration and development." (reply brief, p. 39)

However, it seems inescapably clear from a reading of the *El Paso* decision that the Court held just the reverse, as follows:

(1) The Court held that only *actual tax liability* may be allowed as the income tax component of the cost of service.

> The requirement that the Commission determine a just and reasonable rate is not modified by reading into the statute an exception to the extent that the prices charged may be sufficient to afford a just and reasonable rate *plus* an amount representing a savings in taxes granted to the gas industry. (281 F. 2d 572)
>
> * * * * * * *
>
> . . . whatever federal income taxes were actually paid for the test year should be treated as part of the cost of service regardless of whether these taxes were less than would have been paid but for the depletion allowance and the deduction for intangible drilling expense. No theoretical amount not actually paid can be so included. (281 F. 2d 573)

(2) The Court recognized that the rate of return must include an increment for incentive, but held flatly that this may not be accomplished by merely treating the tax savings as the amount necessary to provide for return and incentive; that instead the necessary increment for incentive, to be included in the return, must be determined on the basis of an inquiry directed to that precise issue accompanied by findings on the amount *actually necessary* to provide such incentive.

> It is the duty of the Commission to fix a rate that represents the cost of service and a reasonable return on the investment, including compensation for consumption of the gas and an increment for incentive, instead of merely *treating* the tax savings as the amount necessary to provide for return and incentive. This can be done only by making the necessary inquiry directed to this issue, building up a proper record, and making findings on the amount *actually necessary* to provide these items. (281 F. 2d 573)

It seems clear that the Tidewater position on this entire subject has now been rendered completely obsolete and untenable by the Commission's *Phillips* decision, and by the Court of Appeals decision in the *El Paso* case, *supra*. That position must finally be rejected in view of the Commission's recent decision in the *Panhandle Eastern* case, Op. 344 (April 27, 1961) 25 FPC 787 where the Commission discussed the holding of the Court of Appeals in the *El Paso* case, and then stated:

> In view of this authority, we are of the opinion that we should allow Panhandle only taxes payable as a result of the statutory depletion and the intangibles. The tax allowances should be computed utilizing these permissible deductions, *and rate of return should be treated as a separate question.* (p. 797, emphasis supplied)

It is accordingly clear that Tidewater is not entitled to any allowance for Federal income taxes in its instant cost of service.

The position of the other parties with respect to the rate of return issue is as follows:

(1) Intervenors do not make any specific recommendation as to a precise rate of return level. However, in their cost of service computed under the *Phillips* approach (Appendix A, initial brief) intervenors use the same 11 per cent rate of return which the Commission adopted for Phillips in Op. 338.

(2) The Staff contends that the over-all rate of return for Tidewater should be no more than 9 percent, reflecting an allowance of 13.2 per cent on equity. (initial brief, p. 20)

Since the Staff's rate of return approach is being adopted here, with some modification, consideration will now be given to the various factors which were used and considered by Staff in deriving its recommended rate of return.

Earnings-Price Ratios

The Staff noted that the earnings-price ratios of 39 integrated and unintegrated gas producers averaged 7.44 percent during the five-year period 1953-1957. (Item S, p. 13) [23] This 39-company group included 15 Class A producers (companies engaged solely in producing operations, producing gas and oil), 3 Class B producers (producers of gas and oil and refiners), 20 Class C integrated producers (producers of gas and oil, refiners and marketers), and one Class D producer (producer of gas and oil engaged in marketing but not refining). It represents the identical group of producers whose earnings-price ratio data and average earnings on equity data were used by the Commission in its consideration of the rate of return question in Op. 340, *United Carbon Company and Columbian Fuel Corporation*, 25 FPC 181, (p. 186). The Staff also noted that during the same period Tidewater's own earnings-price ratios averaged 10.48 percent. The Staff actually used the higher Tidewater earnings-price ratio of 10.48 percent, adding to it an additional .75 percent for cost of financing, and an additional 1.95 percent as an adjustment to the "bare bones" cost of equity, to bring Tidewater's stock price up to 1.40 percent of book value, producing an adjusted earnings-price ratio of 13.18 percent.

Tidewater takes the position (reply brief, pp. 32-36) that earnings-price ratios are not a measure of the cost of capital to gas producers and therefore may not be used or considered in any way. In its attack upon the use of earnings-price ratios, Tidewater argues that earnings-price ratios are a measure of the cost of common stock only when two conditions are met—(1) that stocks are bought by investors primarily for their income producing capacity, and (2) that past and current earnings do not significantly diverge from expected future earnings. Tidewater contends that prices of producer stocks do not reflect either of these conditions; that stock prices of producers are influenced by the market values of what investors assume or guess to be the underlying reserves of oil and gas; that as a result speculative activity characterizes the trading in common stock of producers, and the price behavior is volatile and erratic; that investors purchasing common stocks of an oil and gas producer are not discounting current earnings, but are trying to evaluate earnings three to five years in the future; that producer stocks are not bought for current income but for future growth in income and capital gains; that in numerous instances the prices of producer stocks increased despite a slump of earnings, and vice versa; that any averaging of such erratic data cannot give any rational results and would constitute an unreasonable interpretation of investor behavior.

These Tidewater criticisms of the use of earnings-price ratios are similar to the attacks on earnings-price ratios which were made in the *Phillips* case.

[23] The said Item S represented Staff's rate of return exhibit, Exhibit 23, in the *Murphy Corporation* case, G-9548 *et al.* (25 FPC 334).

They were fully considered by the Commission in Op. 338, and the Commission there stated:

> In past proceedings dealing with the rates of both electric utilities and natural gas pipeline companies we have always considered a number of factors in arriving at a proper allowance for common equity and finally a rate of return. In doing so, we have paid considerable attention to the earnings-price ratio of the company involved and other companies similarly situated. The advantage of the earnings-price ratio as a critique is that it shows what investors will pay for the securities of the company involved in relation to contemporary earnings. But earnings-price ratios have pronounced drawbacks in some proceedings, including this one. Investors are interested in contemporary earnings, but they may be interested in other things as well, such as future earnings, possible discovery of large reserves, tax advantages, a hedge against inflation, so that the market price may reflect factors other than earnings. This is apparently true here, for the record shows that while the earnings on the book value of independent producers' equity have declined somewhat from 1949 through 1955, market prices of their stock have risen substantially. Furthermore, it is plain that potential investors in Phillips are not greatly influenced by Phillips' position in the gas business, since but six percent of its gross income comes from this source. While as we said in the *Southern Natural* case the study of earnings-price ratios over a period of years may properly be used with judgment, together with other factors, in determining a reasonable allowance for equity, this is not a case where earnings-price ratios should be a controlling factor in arriving at a fair rate of return.

The Commission in Op. 338 thereupon turned its attention to earnings-price ratios, earnings to book value ratios, and allowances for common equity granted by the Commission in previous proceedings to pipeline or electric companies. After considering all of these factors the Commission added an additional 2 percent incentive allowance on top of the allowance of 10 percent for equity, *derived under the earnings-price ratio method*, producing an allowance for common equity of 12 percent, which it approved for Phillips.

Subsequently, in another producer rate case, Op. 340, *United Carbon Company and Columbian Fuel Corporation*, the Commission again considered the criticisms against the earnings-price ratio method, and concluded that "earnings-price ratios over a period of years may properly be used with judgment, together with other factors, in determining a reasonable allowance for equity", but that "such other factors must be given considerable weight in determining the rates of return of independent producers." (Op. 340, p. 186) The Commission arrived at this conclusion after the following analysis:

> In past proceedings dealing with the rates of both electric utilities and natural gas pipeline companies, as stated in our *Phillips* opinion, we have always considered a number of factors in arriving at a proper allowance for common equity and finally a rate of return and in doing so we have given some weight with judgment to the earnings-price ratio of the company involved and other companies similarly situated. The advantage of the earnings-price ratio is that it shows what investors will pay for the securities of the company in relation to contemporary earnings. However, investors are frequently moved by other considerations than contemporary earnings; they may be interested in future earnings, possible discovery of large reserves, tax advantages, a hedge against inflation, so that the relationship between earnings and price is not always a complete criterion. This is true of the producers, for the record shows that between 1950

> and 1957 producer earnings on the book value of their shares remained constant or trended downward while market prices increased substantially.

After laying down this *caveat*, the Commission stated: "We think as did the examiner, that the earnings price ratio of 39 companies engaged in the oil and gas producing business is significant. For the 1953-1957 period, the average earnings-price ratio for these companies was 7.4 percent." (p. 186)

In view of these holdings by the Commission in both Op. 338 and Op. 340, it is clear that the Tidewater position with respect to the use of earnings-price ratios must be rejected; that instead earnings-price ratio data may properly be used in this proceeding "with judgment", although it is not to be treated as a "controlling factor".

It is of interest to note that Staff's use in the instant proceeding of the earnings-price ratio data *for its 39-company group of integrated and unintegrated gas producers* has already been directly approved by the Commission in Op. 340, where the Commission characterized the earnings-price ratio data for these companies as "significant" for the purpose of its rate of return analysis. (Op. 340, p. 186) It should also be noted that Staff's use of the time period 1953-1957 in its consideration of earnings-price ratio data has also been directly approved by the Commission in Op. 340, where the Commission accepted and relied upon the identical earnings-price ratio data as presented by the Staff for the same five-year 1953-57 period. Similarly, in the *Phillips* case (Op. 338), the Commission rejected Phillips' attempt to use a 9-year period, 1947-55, for the derivation of an earnings-price ratio, stating:

> We agree with the examiner that the appropriate period was the five years, 1951 to 1955, because that reflects the more recent trend of earnings-price ratios. (Op. 338, p. 571)

In addition to its general attack upon the use of earnings-price ratios, outlined above, Tidewater attacks the method used by the Staff to compute its 1.95 percent adjustment to the "bare bones" cost of equity. The Staff formula used to derive this 1.95 percent adjustment is explained in Footnote 16 on page 19 of Staff's initial brief. Tidewater (p. 36 of reply brief) describes this formula as consisting of "multiplying Tidewater's earnings-price ratio by the proportion by which 1.40 exceeds the actual ratio of market value to book value". Tidewater attacks the Staff's 1.95 percent adjustment on the following grounds:

(1) It contends that the record is totally devoid of any support for any such adjustment, and notes that the Commission stated in Phillips:

> There is no mathematical way to make such an allowance . . . (Op. 338, p. 571)

Tidewater omits to mention, however, that the Commission, immediately after making this statement, concluded:

> . . . we think that the .75 percent used by the Staff witness would be a correct adjustment to make. (Op. 338, p. 571)

(2) Tidewater attacks the time period of 1953-57 used by the Staff in its computation of this adjustment, contending that this time period is wholly inappropriate and unrepresentative of conditions in the more recent past; that Tidewater stock has been selling for the last two years (1959 and 1960) at barely more than two-thirds of its book value, which was over $30.00; that the computation should therefore be made on the basis of data for the years 1959-60, and such a computation would result in an equity allowance of over 20 percent.

It is concluded, however, that the 5-year period 1953-1957 employed by Staff is more appropriate for this purpose, since it is at once long enough to be more truly representative of the long-run situation, while still properly and sufficiently reflecting current and recent trends. There is no evidence to indicate that the relationship of Tidewater market prices to book value which pertained for the two years 1959 and 1960 reflects any continuing trend which can be expected to continue for the future. In addition, it should be noted that the Commission in Op. 338 found that an adjustment of only .75 percent over and above the "bare bones" cost of equity was "a correct adjustment to make". In the instant proceeding the Staff has employed a substantially *higher* adjustment of 1.95%. In the light of these circumstances, the Staff's proposed adjustment to the "bare bones" cost of equity is regarded as satisfactory.

Earnings-Book Value Ratios

Staff's initial brief (p. 19) notes that its 39-company group of integrated and unintegrated gas producers had average earnings-book value ratios of 14.6 percent during the period 1953-57, and that Tidewater itself had an average-earnings book value ratio of 11.92 percent during the same period (Item S, p. 15). The Staff therefore concludes that the 13.2 percent equity allowance recommended by it "provides an earnings-book ratio that lies midway between the industry's 14.6 percent and Tidewater's 11.92 percent." (initial brief, p. 20)

Tidewater attacks this Staff use of earnings-book value ratios on the following grounds (reply brief, p. 37):

(1) It contends that it is irrelevant and circular reasoning to make the return allowance dependent on the return earned by the subject company. This criticism must be regarded as without merit, in view of the fact that the Commission in the *Phillips* case noted "the comparatively high earnings on equity of the integrated companies" (which amounted to 15.3 percent or 14.8 percent depending upon the time period used) and "the even higher earnings of the producers" (which amounted to 19 percent), but then concluded that these were

> offset by the fact that Phillips' own unregulated earnings on equity have been just a little over 12 percent. (Op. 338, p. 573)

(2) Tidewater attacks the Staff's use of its own average earnings-book ratio of 11.92 percent on the ground that this is not the return earned by Tidewater's *production* operation, but by the integrated company. For similar reasons, Tidewater attacks Staff's use of the 14.6 percent earnings-book value ratio of its 39-company group of integrated and unintegrated gas producers, contending that "Tidewater's return on gas operations must be determined by reference to returns earned by *producers*, that engage primarily in production operations, and not by reference to companies whose production earnings are obscured and distorted by refining and marketing operations." (reply brief, p. 37; also initial brief, p. 84-88)

This position was squarely rejected by the Commission in the *Phillips* case, Op. 338, where the Commission, in discussing the use of earnings-book value ratios stated:

> This approach as employed by Phillips, however, mistakenly relies on the Class A producer companies whose operations differ from Phillips' integrated operations. (Op. 338, p. 571)

The Commission then noted and considered the earnings-book value ratios for the Class C integrated companies, for a 40-company group including both integrated and unintegrated producers, and the earnings-book value ratios

for Phillips itself. In addition, in considering Phillips' own experience, the Commission noted and gave weight to the earnings-book value ratio *of the entire integrated company*, making no attempt to determine the return earned by Phillips' production operations alone. In so doing, the Commission reflected its conclusion that "the financing of Phillips and its capital costs are affected by the nature and success *of the whole business*." (p. 569) It is also interesting to note that in Op. 340, *United Carbon Company*, the Commission, in considering earnings-book value ratios in connection with its rate of return discussion, gave consideration to and characterized as "significant" the average earnings-book value ratios of the identical 39-company group of integrated and unintegrated gas producers used by Staff in the instant proceeding. (Op. 340, p. 186)

(3) Tidewater further attacks the Staff's use of earnings-book value ratios on the ground that there is no support in the record for choosing 1953-57 as the base period for the application of the comparable earnings test. Tidewater states:

> While a five-year period is normally sufficient to establish representative averages for traditional public utilities, the substantial variations of producer earnings from one year to the next make it necessary to use a longer period of time. (reply brief, p. 38)

Tidewater accordingly suggests that it is necessary to use a period running from eight to ten years in order to derive meaningful averages.

This contention is completely disposed of by the Commission's treatment of similar problems in the *Phillips* case. In that case Phillips, in employing the earnings-price ratio technique, used the 9-year period 1947-1955, contending that the longer period was more truly representative of the long-run situation. The Commission, however, held:

> We agree with the examiner that the appropriate period was the five years, 1951 to 1955, because that reflects the more recent trend of earnings-price ratios. (Op. 338, p. 571)

The rationale for giving some consideration to *earnings-book value ratios* was explained by the Commission in its *Phillips* decision as follows:

> Although actual earnings related to book value cannot be decisive in determining a fair return, they constitute an important factor as showing what comparable companies are earning on the book value of their assets and the relation of Phillips' earnings to their earnings. (Op. 338, p. 571)

Similarly, in its Interim Rate of Return Order in the *Tennessee Gas Transmission Company* case (Docket G–19983, August 9, 1960) the Commission stated:

> We have, however, given consideration to the evidence of the return on book equity of Tennessee as compared with the other major pipeline companies as a factor in fixing a return which is commensurate with returns on investments of other enterprises having corresponding risks . . .

In view of the rationale set forth above, the mere fact, as stressed by Tidewater, that producer earnings allegedly show substantial variations from year to year, should not cause any concern. Instead, our objective should be to use a period which is recent enough so that it reflects a trend which is representative of what may be expected for the future; but at the same time to use a time period which is sufficiently long to include a representative spread of the highs and lows normally experienced. An examination of the earnings-book value ratios for producers in general, set forth in Staff's Item S, at pp. 14-15, demonstrates that the 1953-1957 period clearly satisfies these standards.

The average earnings-book value ratios, by categories, for each year from 1949 to 1957 are set forth below:

[Percent]

Years	Staff's 39-company group of integrated and nonintegrated gas producers	Class A producers	Class B producers	Class C producers	Class D producers	Tidewater
1949	18.4	21	30.3	15.9	----------	12.4
1950	17.7	17.6	32.2	16.2	----------	14.3
1951	21.3	27.9	27.7	17.1	----------	14.6
1952	17.4	21.3	20.5	15.0	----------	11.2
1953	17.0	19.5	16.9	15.4	17.4	12.8
1954	13.8	14.2	18.0	12.8	17.8	13.4
1955	13.8	14.4	12.5	13.3	18.5	12.3
1956	14.2	14.1	15.1	14.2	15.4	11.8
1957	14.2	15.6	17.2	12.7	16.4	9.3

The above figures show clearly that the earnings-book value ratios for the years 1949-1950 and 1951 were unusually high; that beginning with the year 1952 such ratios have trended downward; that accordingly the addition of data for the years prior to 1953 would have a distorting effect, producing a ratio not representative of the future; that the period 1953-1957 more correctly indicates what comparable companies are currently earning on the book value of their assets, and what they may be expected to earn on book value in the future.

The Commission reached this same conclusion in Op. 340, *United Carbon Company*, where it stated:

> the record shows that between 1950 and 1957 producer earnings on the book value of their shares remain constant or trended downward . . . (p. 186)

In that decision the Commission characterized as "Also significant" the average earnings on equity of the same 39-company producer group here used by the Staff, using the data for the identical 1953-1957 time period which is relied on by the Staff in the instant case. The Commission there took note of the fact that "These earnings averaged 14.4% for the period 1953-1957." (p. 9)

Although earnings-book value ratios thus constitute a significant factor to be considered here, there is one *caveat* which must be borne in mind in this connection. In its Order Denying Application for Rehearing, issued September 27, 1960 in the *Tennessee Gas Transmission Company* case, Docket G-19983, 24 FPC 525, the Commission stated:

> One such other factor is earnings on book equity, and Tennessee relies heavily in support of a higher allowance for equity on evidence of such earnings. We have given due consideration to this evidence as a factor in our determination of the allowance to be made, although such return cannot be taken as a direct measure of the allowance for equity. Such return includes contingent earnings under rates subject to refund in proceedings before the Commission. To fix a rate of return for the future on the basis of the historical return on book equity as Tennessee urges would be improperly to validate such contingent earnings. (p. 526)

In addition, in a subsequent pipeline rate case, *Kansas-Nebraska Natural Gas Company, Inc.*, Op. 343, (March 8, 1961), 25 FPC 448, the Commission in discussing the rate of return issue referred to "earnings on equity" data as "while not controlling, but of significance"—but concluded with the statement that

> These earnings are subject to the disability that they include non-jurisdictional business and reflect earnings subject to refund. (p. 452)

It is relevant to note that the earnings-book value ratios of gas producers are subject to the "disability" referred to by the Commission in the above decisions—*i.e.*, they reflect and include earnings under rates which are subject to refund in proceedings presently pending before the Commission. This situation does not represent a "disability" in connection with earnings-*price* ratios, since we are there only interested in measuring what investors will pay for the common stock in relation to earnings. However, in the case of earnings-*book* value ratios the relevance and significance of these ratios lies in the fact that they show "what comparable companies are earning on the book value of their assets" (Op. 338, p. 571). In this latter case, to the extent that the earnings figures include substantial amounts which may later be subject to refund, these figures may not show an accurate picture.

Equity Return Allowed Various Pipelines

The Staff also lists "returns on equity for pipelines" as another factor to be considered, and concludes that its recommended 13.2% equity allowance would be "above the equity return allowed various pipelines". (initial brief, pp. 19-20)

The Tidewater reply brief (p. 38) assails this Staff conclusion as "clearly in error". Tidewater contends that the record shows that a representative group of nine natural gas pipelines had average earnings of 14.9% on common equity in the 1950-57 period (Exh. 138, Sched. 28), and that the Commission itself "stated in Trunkline Gas Co. *et. al.*, Op. 339 . . . that nine pipelines had average earnings of 15.7% on common equity in the years 1955-59." Tidewater concludes that on this basis its return on equity should be above 15 percent. In support of this conclusion, it cites the Commission statement in *Phillips*, Op. 338 (p. 572) that:

> It is clear that the risks of this business are greater than those of an electric utility or natural gas pipeline. While we cannot rigidly compare these companies with Phillips, for the circumstances and times are different, we do think that *an allowance for common equity* for a producer should be comparable to or greater than that for a pipeline company or an electric company. (emphasis supplied)

It is important to note, however, that in the *Phillips* case the Commission at this point set forth data showing the return or allowance which *the Commission had granted* for common equity in a number of different pipeline or electric utility cases, in decisions issued in the years 1949, 1954, 1956, 1958 and 1960. The allowances granted for common equity in these decisions ranged from 8.64% up to 14.4%. After reviewing this data, however, the Commission in Op. 338 finally approved an equity allowance for Phillips of *12%*. It is interesting and significant to note that this approved equity allowance was two percentage points above the allowances granted by the Commission in the two *1960* pipeline decisions which were included in the above-mentioned pipeline equity allowance table—*i.e.*, (1) the *Southern Natural Gas Co.* (G–20509) decision of July 8, 1960, 24 FPC 26, approving a 10.18% equity allowance, and (2) the *Tennessee Gas Transmission Co.* (G–19983) decision of August 9, 1960, 24 FPC 204, approving a 10.12% equity allowance.

Subsequently, in Op. 340, the *United Carbon and Columbian Fuel case*, the Commission stated:

> In the *Phillips* case we cited several electric and gas pipeline cases showing *allowances* for common equity ranging from 8.64% up to 14.4 percent because we were of the opinion that the allowances for common

equity for a producer should be comparable to or greater than that for a pipeline or an electric company.

The Commission then proceeded to grant an allowance of 11.5% on common equity for United Carbon, and 11% for Columbian Fuel. (p. 187)

It should be noted that the Tidewater contention, outlined above, is based upon a totally different use of pipeline data than that which the Commission employed in its *Phillips* (Op. 338) and *United Carbon* (Op. 340) decisions, *supra*. The pipeline data cited by Tidewater consists of the average earnings made and enjoyed by nine selected pipelines on their common equity in the period 1950-1957—whereas it seems clear that under the standard laid down by the Commission in its *Phillips* and *United Carbon* decisions, our concern should be with the level of the *allowances* on equity *which the Commission is currently approving* for pipeline companies, *under current conditions*. Under the standard as thus laid down by the Commission, the relevant fact to be noted here is that the Commission in the most recent period of 1960-1961 has been uniformly granting allowances on common equity in pipeline rate proceedings in the range of 10% to 10.8%, as follows:

[Percent]

	Allowance on common Equity	Equity ratio
Kansas-Nebraska Natural Gas Company, Inc. Op. 343 (Mar. 8, 1961)	10.8	33.78
Manufacturers Light & Heat Company 23 F.P.C. 446 (Feb. 25, 1960)	10	40
Northern Natural Gas Company Op. 342 (Mar. 7, 1961)	10.5	31.37
Panhandle Eastern Pipeline Company G-19780, Order of Mar. 20, 1961	10.47	40.02
Southern Natural Gas Company 24 F.P.C. 26 (July 8, 1960)	10.18	35.8
Tennessee Gas Transmission Company G-19983, Interim Order of Aug. 9, 1960	10.12	29.5

Under these circumstances, if Tidewater were here allowed a return of 13.2% on common equity, as recommended by the Staff, such an allowance would be 2.4 percentage points higher than the maximum equity allowance approved by the Commission in pipeline rate proceedings in the most recent current period.

Tidewater Allegations Re High Risk Borne By Gas Producers

In Tidewater's initial brief, the rate of return presentation is opened with a lengthy discussion (pp. 66-76) of the alleged "high risks" borne by natural gas producers. In its reply brief (pp. 38-39) Tidewater charges that the Staff discussion of rate of return is marked by "the total absence of any discussion of the fundamental risk characterizing gas operations, namely the risks associated with exploration". On the other hand, intervenors' reply brief takes issue with each of these general allegations, in a lengthy argument at pp. 4-12. This entire discussion, however, plows ground which was fully covered in a most extended manner in the *Phillips* case, in such a way as to make it quite unnecessary and unfruitful to re-hash these matters in the instant proceeding. In the Commission's discussion of rate of return in the *Phillips* case, it took note of and considered the "extensive presentation" there made by Phillips, which embodied "complaints about the hazards of and the meager returns from exploration and development". Having thus considered the problem of the risk borne by gas producers, the Commission there concluded that "some allowance must be made in the rate of return" to provide the required incen-

tive "to promote the continued exploration for and production of gas". The Commission thereupon resolved this problem in Op. 338 by adding two percentage points to the 10 percent allowance which had been derived for common equity under the earnings-price ratio method [34], producing an ultimate allowance of 12 percent for common equity. [35]

In its subsequent decision in the *United Carbon Company* case, Op. 340, the Commission again considered the additional incentive required for independent producers, stating:

> Furthermore, to maintain the present rate of deliveries there must be an expanded program of drilling, and to find new gas reserves, wells must be drilled to the deeper horizons at increasing cost. Thus, there must be a sufficient incentive to enter into such a program in view of the increased difficulties and expenses involved, even though the record shows that the ratio of successful wells to total wells drilled has been high.

The Commission then concluded that this objective was met by providing an allowance of 11.5 percent on common equity for United Carbon and an allowance of 11 percent for Columbian Carbon, citing its action in the *Phillips* case. (Op. 340, p. 186)

Relevant Tidewater Operating Characteristics

In its *Phillips* decision the Commission took into consideration, among other things, certain favorable characteristics with regard to Phillips' financial condition and operations. It stated in this connection:

> Phillips, as already noted, is a large company with assets of over a billion dollars, whose gas business is only a small fraction of the whole. Such a company is in a very strong position to raise capital. As a company with a continuing program of exploration and production it differs from other companies whose activities are sporadic or are merely holding reserves. (Op. 338, p. 569)
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> * * * * * * *
>
> . . . we also bear in mind that Phillips is a large company and well established in the conduct of its gas business, its oil business and its other extensive operations. (Op. 338, p. 573)

The record in the instant proceeding indicates similarly that Tidewater occupies a favorable position in the industry, as indicated by the following facts which are adopted from the intervenors' initial brief, at pages 5-6:

> Tidewater, like Phillips, is a fully integrated oil company, with investments on all levels of the oil industry. In 1957, its sales and other revenue totalled $594,386,000, and its capital expenditures $140,231,000. Of the latter total $88,462,000 was expended for facilities to refine, transport and market crude oil and its products. The company's net production of crude oil in 1957-34, 119,000 barrels—accounted for less than half of its refinery throughput of 77,005,000 barrels (Ex. 144, p. 22)
>
> By any standards Tidewater, like Phillips, is a 'major' oil company. In

[34] The 10 percent allowance was derived by adding to an average earnings-price ratio of 8.5 percent: (a) an allowance of .75 percent for the cost of financing, and (b) an investment factor of .75 percent over the "bare bones" cost of equity, designed to maintain the market price of Phillips common stock at around 1.40 percent of book value, in order to enable the company to attract capital at reasonable cost.

[35] In its later Op. 344, *Panhandle Eastern*, p. 18, the Commission characterized this process which it had gone through in Op. 338 as follows:

In the *Phillips* case we added two percentage points to the 10 percent allowance for common equity in order to provide this incentive.

1957 it ranked twelfth in assets and fourteenth in sales among all oil companies. Similarly, Tidewater, like Phillips, is among the largest producers of natural gas. In 1957 its direct sales of gas in interstate commerce placed the company among the top twenty producers. Like Phillips, its natural gas revenues sharply increased during the decade of the 1950's, rising no less than 319.4 per cent between 1950 and 1957, or from $3,390,000 to $14,218,000 (Ex. 138, Sched. 3, p. 2). In spite of this, the relative importance of these revenues to the company as a whole remains relatively small, in which respect its situation again is remarkably akin to that of Phillips. Thus, in 1957, Tidewater's natural gas sales of 105,154 MMcf accounted for only 2.38 per cent of the company's consolidated total revenues (Ex. 138, Sched. 3, p. 2)

In addition, it is relevant to note that Tidewater's earnings available for common stock on a per share basis ranged between $2.00 and $2.84 during the period 1950 to 1957 (31:4960); and that its net worth increased from $255,550,000 as of December 31, 1950, to $449,634,000 at December 31, 1957. Its reserves of natural gas increased by 139.77 percent during this period. (31:4963) Tidewater's reserves of natural gas in 1950 were equivalent to 29.8 years of production, whereas the reserves of natural gas for the United States as a whole amounted to only 26.9 years of production. Similarly, in 1957 Tidewater's gas supply was equivalent to 27.4 years of production, as compared with the lower figure of 21.4 years on a nation-wide basis. Thus Tidewater's position was continuously maintained at a higher level than that for the United States as a whole. (31:4963)

Tidewater's natural gas sales rose from 40,059,000 Mcf in 1949 to 121,531,000 Mcf in 1958. (Exh. 144, p. 22) The average price received by Tidewater for its natural gas sales rose from 7.5 cents in 1950 to 13.5 cents in 1957. (Exh. 144, p. 22; Exh. 138, Sched. 3, p. 2)

It is true that Tidewater's net income for 1958 showed a deficit of 3 cents per share. However, in the company's annual report for that year, this situation was explained as having resulted principally from "limited access to low-cost raw materials due to imposition of Federal controls on oil imports and allocation to Tidewater of an inequitable import quota." (Exh. 144, p. 3) It should be noted, however, that this was only a temporary situation and that Tidewater's earnings had again risen to $2.23 per share in 1959 and $2.39 per share for the twelve months ending September 1960. (Tidewater reply brief, p. 36, footnote 36)

Summary of Determinative Rate of Return Factors

A. *The Phillips Case*

In the *Phillips* case (Op. 338), the Commission gave consideration to the following factors:

(1) *Earnings-Price Ratios*—The Commission noted that Phillips' average earnings-price ratio for the 5-year period 1951-1955 was 8.8 percent, and that the 5-year average for a 41-company group, including Class A, Class B, and Class C producers, was 8.5 percent. Following and adopting the Staff method as there presented, the Commission added to the 8.5 percent average earnings-price ratio of the 41-company group an allowance of .75 percent for the cost of financing, and a further allowance of .75 percent over the "bare bones" cost of equity as an investment factor designed to maintain the market price of Phillips common stock at around 1.40 percent of book value. This resulted in an adjusted earnings-price ratio of 10 percent.

(2) *Earnings-Book Value Ratios*—The Commission gave consideration to the earnings-book value ratios for the Class C integrated companies, which

amounted to 14.8 precent for the five-year period 1951-1955 and 15.3 percent for the seven-year period 1949-1955; and the earnings-book value ratios of the 40-company group of integrated and unintegrated producers, amounting to 17 percent for the five-year period 1951-1955. However, the Commission gave weight to the fact that Phillips' own earnings-book value ratio had been only 12.3 percent for the five-year period 1951-1955 and 12.1 percent for the seven-year period 1949-1955.

(3) *Equity Return Allowed for Pipelines*—The Commission gave consideration to the fact that it had approved allowances for common equity ranging from 8.64 percent up to 14.4 percent in electric and gas pipeline cases, in decisions issued between 1949 and 1960.

(4) The Commission concluded that an additional increment should be added to the determined allowance for common equity, in order to provide the required incentive to encourage continued exploration for and production of gas.

(5) The Commission noted that Phillips' capitalization consisted of 88.4 percent equity and only 11.6 percent debt. It concluded that Phillips' allowance for common equity should be limited by its high equity capitalization, which contributed to reducing the risk.

(6) It finally noted that Phillips was "a large company and well-established in the conduct of its gas business, its oil business and its other extensive operations." (Op. 338, p. 574)

(7) After considering all of the above factors the Commission added two percentage points, as an incentive factor, to the adjusted 10 percent allowance for common equity derived under the earnings-price ratio method—producing a final allowance for common equity of 12 percent, and this resulted in an over-all rate of return of 11 percent for Phillips.

B. *The United Carbon Company case (Op. 340)*

In the United Carbon Company case the Commission gave consideration to the following factors: (a) the average earnings-price ratios of 39 integrated and unintegrated producers, amounting to 7.4 percent for the five-year period 1953-1957; (b) the need for an additional allowance necessary to cover cost of financing and to enable the company to attract capital at reasonable cost; (c) the average earnings-book value ratios for the 39-company producer group amounting to 14.4% for the period 1953-1957; (d) the allowances for common equity in electric and gas pipeline cases, ranging from 8.64 percent to 14.4 percent. The commission then took note of the fact that in the *Phillips* case it had approved an allowance of 12 percent on common equity and an over-all rate of return of 11 percent. After considering all these factors, the Commission approved an allowance of 11.5 percent on common equity for United Carbon, and 11 percent for Columbia Carbon, producing an over-all rate of return of 11 percent for United Carbon and 10 percent for Columbian Fuel Corporation.

C. *The Instant Tidewater Proceeding*

In the instant Tidewater proceeding, in addition to all of the considerations set forth above, particular weight has been given to the following factors:

(1) Earnings price ratios: Tidewater's own earnings-price ratios, averaging 10.48 percent for the five-year period 1953-1957.[36] There has been added to this figure an additional 1.95 percent (proposed by Staff) as an adjustment over "bare bones" cost of equity (this being substantially higher than the

[36] This, of course, is a substantially higher earnings-price ratio than the average earnings-price ratios for the same period for the 39-company group of integrated and unintegrated gas producers amounting to 7.44%.

similar adjustment of .75 percent adopted by the Commission in the *Phillips* case, *supra*). The result is to produce an adjusted earnings-price ratio in this case of 13.18 percent.

(2) *Earnings-book value ratios*—Consideration has also been given to Tidewater's own average earnings-to-book value ratio of 11.92 percent for the five-year period 1953-1957, and the earnings-book value ratios averaging 14.6 percent for the 39-company group of integrated and unintegrated producers during the same period.

(3) *Equity return allowed to pipelines*—Consideration has in addition been given to the allowance on equity approved by the Commission in pipeline rate proceedings during the years from 1949 to 1960, ranging from 8.64 percent to 14.4 percent, with particular recognition of the fact that such allowances have been approved only in the range of 10 percent to 10.8 percent during the most recent period 1960-1961.

(4) *Additional incentive to encourage continuing exploration for and production of gas*—If we here added to the adjusted earnings-price ratio of 13.18 percent, referred to above, the same incentive factor of two percentage points which was adopted by the Commission in the *Phillips* case, this would bring the Tidewater allowance for common equity up to a level of roughly 15 percent. It is of interest to note that such a 15 percent equity allowance would be substantially higher than Tidewater's own average earnings-book value ratio of 11.92 percent. It would also be higher than the maximum equity allowance approved by the Commission in the previous electric and gas pipeline cases cited in Op. 338, and far higher than the equity allowances ranging from 10 percent to 10.8 percent which the Commission has been approving in pipeline rate proceedings in the most recent period of 1960-1961. It is further noted that it would be substantially higher than the 12 percent equity allowance which the Commission approved for Phillips in Op. 338, or the 11.5 percent and 11 percent equity allowances approved by the Commission for United Carbon Company and Columbian Fuel Corporation in Op. 340. It is recognized, however, that Tidewater with an equity of 55.7 percent has a thinner equity than either Phillips, United Carbon Company, or Columbian Fuel Corporation—and this factor must be taken into account.

Under all the circumstances, it is concluded that an equity allowance of 15 percent for Tidewater represents the maximum allowance which can be justified in this case.

On the basis of a 15 percent allowance on common equity, an over-all rate of return of 10.025 percent is obtained, which should be rounded off to 10 percent. It is therefore concluded that a fair rate of return for Tidewater in the instant proceeding is 10 percent.

Tidewater Contention That Its Producing Operations Should be Treated As Financed Entirely By Common Stock

Tidewater contends that its rate of return should not be computed on the basis of its *actual* capitalization, including 55.7 percent equity ratio, a 35.3 percent debt ratio, and a 9 percent preferred stock ratio; that instead its producing operations should be treated as having been financed entirely by common stock and its rate of return should therefore be computed on the basis of a 100 percent equity ratio; that, in the alternative, its rate of return should be computed on the basis of imputing to its operations a fictitious capitalization of 95% equity ratio and 5% debt ratio, representing the average ratio of common stock capital to total capital for eight selected strictly producer companies (Class A producers).

In support of this position, Tidewater contends that a detailed study of its debt financing reflects that "'practically its entire debt' was incurred in connection with the expansion of refinery transportation and marketing operations." (reply brief, p. 79) This conclusion itself is subject to some doubt, since Tidewater's own evidence established that it has floated many millions of dollars of bonds expressly for the financing of production operations. As Tidewater itself notes (reply brief, p. 31) the Prospectus issued in 1956 in connection with its flotation of debt securities showed the application of proceeds from debt financing and bank borrowing as including $53 million for "Domestic and foreign exploration and acquisition and development of prospective and proven oil and gas properties, including the offshore drilling program." Tidewater rate of return witness, Badger, concluded that the funds obtained by debt financing and bank borrowing which were shown in this Prospectus as designed for use in connection with exploration and development operations must actually have been used instead for Tidewater's refining and marketing operations, with the result that all of the funds devoted to exploration and production during the period must have come from self-generated funds or internally-generated funds (37:5730-32). This, however, was mere speculation. Tidewater itself did not rely upon or attempt to use this explanation in its reply brief—but instead substituted a totally new explanation, *i.e.*:

> The $53,000,000 fund set aside for exploration and development was earmarked for *both* domestic and foreign operations so that it is quite apparent that only a small portion of debt financing, if any, was earmarked in connection with domestic exploration or production operations. (reply brief, p. 31)

However, this conclusion is equally speculative.

Furthermore, entirely apart from the speculative factual question referred to above, the Tidewater position is erroneous as a matter of *principle*, in that it represents an attempt to determine the rate of return required to maintain Tidewater's financial integrity and to enable it to raise the necessary capital, not on the basis of the nature and success of its entire operation, but rather by treating it as if it were engaged solely in the oil and gas production business. This approach was completely rejected by the Commission in the *Phillips* case where, in connection with a somewhat similar problem the Commission stated:

> Phillips argues that it is a fallacy to apply to gas production operations a rate of return based upon the over-all cost of its capital because of the peculiarly risky nature of the oil and gas production business. It says that the cost of capital for the enterprise as a whole is less than the cost of capital for these risky operations. *However, the financing of Phillips and its capital costs are affected by the nature and success of the whole business*, and it would be impossible on this record to determine the cost of capital for part of its business. (p. 569, emphasis supplied)

A final flaw in this Tidewater position lies in the fact that if its rate of return were to be computed on the basis of imputing to its operations a fictitious capitalization of 95 percent equity ratio and 5 percent debt ratio, representing the average ratio of common stock capital to total capital for eight selected strictly producer companies (Class A producers), it would then be necessary for purpose of consistency, to use in our earnings-price ratio calculation the *substantially lower* average earnings-price ratios for the period 1953-57 *of the Class A strictly producer group*, amounting to 5.2 percent—in place of Tide-

water's own average earnings-price ratio of 10.48 percent which was used in the Staff calculation. In other words, if Tidewater is thus to be converted into a strictly producer Class A company, for the purpose of the rate of return computation, then it seems clear that in applying the earnings-price ratio computation the average earnings-price ratios of the Class A strictly producer group should be employed. The Commission recognized this very consideration in Op. 338, in connection with its rejection of the Phillips contention that its rate of return should not be based upon the over-all cost of its capital, but rather upon the basis of its oil and gas production operations alone. After concluding that "the financing of Phillips and its capital costs are affected by the nature and success of the whole business", the Commission went on to point out:

> Furthermore, the evidence indicates that the companies that are solely producers have a higher market demand for their equity securities in relation to earnings than the companies with integrated operations. This is possibly because investors sought a hedge against inflation and invested in these stocks in order to acquire a share in raw materials in the ground. In any case, investors, according to the record, appear willing to accept a lower return from purely producing companies than from the integrated companies.

It would be interesting, in connection with this Tidewater proposal, to make a rough computation of the type of rate of return which would be derived here if we were to substitute the average earnings-price ratio of the Class A strictly producer companies, amounting to 5.2 percent, in place of the Tidewater 10.48 percent earnings-price ratio used by the Staff. If we added to the 5.2 percent figure an additional .75 percent for cost of financing, and the same 1.95 percent "bonus" used by Staff, the result would be an adjusted allowance for equity of 7.90 percent under the earnings-price ratio method. If we further added to this figure the same additional 2 percent allowance added by the Commission in Op. 338 to provide the necessary incentive to encourage continued exploration for and production of gas, the final result would be an equity allowance of 9.90 percent. Using Tidewater's suggested capitalization of 5 percent debt and 95 percent equity, this would produce a rate of return of 9.58 percent—somewhat lower than the 10% rate of return here approved.

The final answer to this Tidewater contention is as follows: In Op. 338 the Commission did not adopt the method here urged by Tidewater, but instead computed Phillips' required rate of return on the basis of its *actual* capitalization including 88.4 percent equity and 11.6 percent debt. At the same time, the Commission characterized Phillips' actual equity ratio of 88.4 percent as a relatively *high* equity ratio, which "reduces the risk found in companies of thinner equity". The Commission then included

> While we believe that Phillips should be granted an allowance for common equity in excess of 10% our allowance will be limited by Phillips' high equity capitalization. (Op. 338, p. 573)

Thus we are confronted in the instant proceeding with a Tidewater proposal that its rate of return should be computed on the basis of a fictitious capitalization, under which there should be imputed to it a *higher* fictitious equity ratio as a basis for *increasing* the computed rate of return. Yet, in Op. 338 the Commission used Phillips' actual capitalization and treated its high equity ratio as a basis for *limiting* the equity allowance required for Phillips.

In view of all the considerations outlined above, it is concluded that the instant Tidewater proposal should be rejected and that its rate of return should be computed upon the basis of its actual capitalization.

Tidewater's Market Price Argument

At pages 98-109 of its initial brief, Tidewater makes an elaborate argument designed to establish that its market price evidence presented in the instant proceeding confirms the lawfulness of its natural gas prices. In this connection, it asserts that in order to apply the competitive market price standard it must first be established "that effective and workable competition exists in the market in which producers sell natural gas". It then proceeds to argue that there *is* "effective competition", on the basis of elaborate evidence incorporated by reference from the *Omnibus* proceeding. Tidewater accordingly contends that the market price evidence which it has presented in the instant proceeding is relevant and determinative, and that it fully confirms the lawfulness of its jurisdictional gas rates.

An extended consideration and discussion of this Tidewater market price argument has been rendered unnecessary by the recent decision of the Court of Appeals in *The United Gas Improvement Company* v. *F.P.C.*, 290, F. 2d 133. (C.C.A. 5, February 22, 1961). The majority decision of the court in that case disposes of the market price argument in such simple and lucid terms, cutting through to the very heart of the matter, that no substantial further comment would seem to be required. In that case (involving a question as to the imposition of a rate condition in a producer certificate proceeding) the court held that field price evidence was not sufficient to justify the initial rate there proposed, stating:

> The only evidence on this record that supports such 'out-of-line' price is the fact that it was negotiated at arm's length and was required by the intense competition. This, as we have said, is not enough. (slip opinion, p. 13)

The court recognized that there was "intense competition" and a "highly competitive market". However, the court held:

> As we have previously stated in *Bel Oil Corp.* v. *F.P.C.* . . . a price paid for gas as the result of arm's length bargaining with the producer is not, merely because bargained for in a highly competitive market, 'just and reasonable' within the intendment of the Natural Gas Act. . . . This is so because the only justification for giving the Commission the duty to regulate prices was the determination by Congress that *the producers have a supply that is so restricted in relation to demand that they have the economic power to bargain for prices that will be injurious to the public.* (slip opinion, p. 6)
>
> * * * * * * *
>
> This discussion by the responsible parties who fixed this initial price makes it perfectly plain that a substantial part of the increase from 'nine to twelve cents' to 21½ cents *resulted from the tremendously increased demand as contrasted with the available supply.* (slip opinion, p. 8) (emphasis supplied)

Under these circumstances, the court concluded that the mere fact that the proposed price had been bargained for at arm's-length, or that the prices "were not higher than a price someone else was then paying in the area" was not sufficient. (slip opinion, p. 7)

The court then addressed itself to the question as to how the Commission might properly determine whether an initial price was "out of line" in such a way as to require the imposition of a rate condition. It stated:

> The principal question here is whether the line is established by proof of what others are paying under certificates that were either uncontested or were being appealed and are thus 'suspect,' or what others are paying based on such 'suspect' rates, or what even unregulated intrastate purchasers are paying. (slip opinion, p. 11)

The court concluded that "the line" could not be satisfactorily established by any of these different types of field price situations.

The court finally held that a price "much higher than any theretofore certificated *according to the standards found by the reviewing court to be consonant with CATCO* will unquestionably breach 'the line'." (slip opinion, p. 12-13)

It appears to be the clear implication of the above language that only field prices which had previously been certificated by the Commission under standards consistent with the principles laid down by the Supreme Court in its CATCO decision (*The Atlantic Refining Co., et al.* v. *Public Service Commission of the State of New York, et al.*, 360 U. S. 378, may properly be considered in arriving at a determination as to what is "out of line".

The usefulness of market price evidence of this type was similarly questioned by a decision of the Ninth Circuit in *The United Gas Improvement Co.* v. *F.P.C.*, 283 F. 2d 817, (Oct. 31, 1960), another rate condition case where the court held:

> When an order certificating an initial rate is under court or Commission review, it is possible that the certificate may be eventually denied or price conditions may be attached. In our opinion an existing rate subject to such a hazard does not provide a reasonably reliable basis upon which to predicate a price line. In the event the existing rate is later modified or conditioned as a result of the pending proceedings the foundation of the line derived therefrom would be undermined. Moreover, the acceptance of questioned existing prices as a guide in setting the line might itself have the anomalous effect of creating a standard by which the questioned rates would then be judged.
>
> For the reasons indicated we are of the opinion that it would be an abuse of discretion for the commission in establishing a price line to rely upon producer prices which are under such a cloud.
>
> *We go further and express the view that where a substantial number of certificated prices are thus under court or Commission review, like prices in the same area though not currently under review ought to be regarded as suspect. In such circumstances it would seem that such similar* prices ought not to be relied upon in fixing a line except upon evidence and findings to the effect that they are not subject to the same infirmities which are under test in the pending proceedings. (283 F. 2d at 824; emphasis supplied)

A similar decision was issued by the Court of Appeals for the District of Columbia Circuit in *Public Service Commission of the State of New York* v. *F.P.C.*, 287 F. 2d 143 (Dec. 8, 1960).

There can be no doubt that the market prices (or field prices) cited by Tidewater in the instant proceeding have not been subjected to the tests required by the Supreme Court's decision in CATCO, or by the above-mentioned Court of Appeals decisions. Furthermore, there can similarly be no doubt that

the field prices cited by Tidewater relate to sales in areas where a substantial number of certificated prices are under court or Commission review.

It is true that the decisions referred to above involved the rate condition question in producer certificate proceedings. However, if field prices which have thus been branded by the courts as "suspect" cannot properly be used as a basis for determining whether to impose a rate condition in a certificate proceeding, where the only object is to hold the line until a determination can ultimately be made as to the "just and reasonable" rate for such sales, then certainly such "suspect" field prices may not properly be relied upon as a basis for determining the "just and reasonable" rate itself—this being the end objective of all price regulation by this Commission.

Tidewater's Presentation with Respect to "Cost Trends and Economic Evidence"

At pages 109 to 117 of its initial brief Tidewater makes an extended argument to the effect that cost trends and general economic evidence confirm the reasonableness of its natural gas prices, relying upon substantial evidence which it presented in this proceeding with respect to trends in production, exploration and development as evidenced by industry experience and by the operations of its own Southern Division. A great part of this evidence was similar to the major presentation made by Phillips Petroleum Company in the *Phillips* case with respect to the economic, geological and engineering aspects of our national gas supply. The Commission in its *Phillips* decision referred to and gave weight to these historical trends and concluded that

> In view of these practical problems in the gas industry some allowance must be made in the rate of return to promote the continued exploration for and production of gas. (Op. 338, p. 573)

The Commission dealt with this problem by granting Phillips an additional allowance of two percentage points, as an incentive factor to be added to the straight allowance for common equity. As already noted in the earlier discussion of the rate of return question in this decision, the same incentive allowance has been included in the approved rate of return for Tidewater in the instant proceeding.

It is concluded here that this is the only appropriate manner in which the "cost trends and general economic evidence" referred to by Tidewater may be reflected in the rates to be approved herein. In reaching this conclusion, it is to be borne in mind that unless such fragmentary cost data is considered in terms of, and as an integral part of a full cost-of-service, it cannot provide a measuring stick or standard to be used for an objective determination of "just and reasonable" rates, but could only be used subjectively as a basis for rationalizing a pre-determined rate.

It is accordingly concluded that the Tidewater presentation with respect to "cost trends and general economic evidence" can suitably be considered only in connection with the rate of return issue, and that it cannot provide, in itself, an independent basis for approval of Tidewater's jurisdictional gas prices.

The cost-of-service herein adopted for Tidewater using the methods described in detail in the instant decision, is set forth in summary fashion in Appendix A, Tables 1-7, at the end of this decision.

This cost-of-service is derived basically from intervenors' Exhibit 180 and from Appendix A at the end of intervenors' initial brief, modified and ad-

justed to reflect the following changes, all of which have previously been discussed in detail:

(1) elimination of gasoline and cycling plant expenses from off-lease expenses charged to gas,

(2) elimination of gasoline and cycling plant investment from off-lease net investment charged to gas,

(3) recomputation of the allocation factor for exploration and development costs under the Commission's *Phillips* modified Btu method, to reflect: (a) the substitution of an economic factor of three, instead of a factor of four; (b) elimination of the economic adjustment factor with respect to the Btu content of plant liquids;

(4) recomputation of the working capital allowance according to the Commission's traditional approved method,

(5) the use of a year-end rate base instead of average rate base,

(6) allowance of a 10 percent rate of return, in place of the "hypothetical" 11 percent rate of return employed by intervenors.

The result is to produce a total jurisdictional cost-of-service for Tidewater, based upon the 1957 test year, in the amount of 11.45 cents per Mcf. (Appendix A to this decision Table 1) As noted by the intervenors (initial brief, p. 32) Tidewater's rates charged for gas sold under rate schedules in effect during the 1957 test year yielded an average revenue of 14.5 cents per Mcf. and it is thus apparent that Tidewater's jurisdictional revenues for the test year 1957 on an over-all basis exceeded its jurisdictional cost-of-service by 3.05 cents per Mcf.

In determining whether Tidewater's rates are excessive, both the Staff and the intervenors adopted the normal and traditional approach of comparing Tidewater's test year *jurisdictional* cost-of-service with its *jurisdictional* revenues. In order to make the comparison on this basis, it was necessary to obtain data with respect to Tidewater's 1957 jurisdictional revenues and volumes. Because no evidence was presented showing Tidewater's jurisdictional revenues or volumes for that year, both the Staff and the intervenors have relied in their briefs upon the jurisdictional revenue and volume figures obtained from Tidewater's 1957 Form No. 301, on file with the Commission. The Staff correctly points out (initial brief, p. 22, footnote 18) that if such data had in fact been presented in evidence during the hearing, it would have been derived from the same source which provided the basis for Tidewater's Form No. 301. The Staff further points out that Tidewater, of course, attested the accuracy of its Form 301 at the time of its filing.

Tidewater, however, contends (reply brief, pp. 41-44) that its total system-wide cost-of-service should be compared with its total 1957 gas revenues derived from both jurisdictional and non-jurisdictional sales, which amounted to 12.49 cents per Mcf. (Exh. 132, Sched. 5) If the jurisdictional unit cost derived here were compared with this latter revenue figure, the comparison, of course, would be far less unfavorable to Tidewater.

On the face of it, the type of comparison here proposed by Tidewater is irrelevant and does not fairly measure what we are trying to determine here—*i.e.*, whether Tidewater is receiving excessive revenue under its existing rates for jurisdictional sales. It is apparent from the above figures that its non-jurisdictional sales were being made in the test year at relatively lower prices, on the average, than its jurisdictional sales. Accordingly, the result of adopting the Tidewater approach would be that, without any understandable justification, we would be attributing to its jurisdictional sales a totally irrelevant unit revenue figure.

The only question to be resolved here, under the circumstances, is whether the 1957 jurisdictional volume and revenue figures obtained by Staff and intervenors from Tidewater's 1957 Form 301 are properly usable in this proceeding for the purpose of determining the company's 1957 jurisdictional revenues.

In its reply brief at pages 41-44, Tidewater makes a strong attack upon the use of its 1957 Form 301 volume and revenue data, both on a number of substantive grounds and for the reason that this data was not made a part of the record as evidence in the instant proceeding. It suggests that its 1957 Form 301 figures cannot properly or reliably be used for this purpose because of a number of suggested complications which it there sets forth in detail.

The fact is that this same type of attack on the use of Form 301 data for this purpose was made by Tidewater counsel at an early stage of the hearing, in connection with the attempt by a Staff witness to employ 1955 Form 301 data as a basis for showing 1955 jurisdictional revenues and volumes. Tidewater counsel at that time suggested that the same type of alleged inaccuracies and complications were inherent in the use of its 1955 Form 301 data as it now raises with respect to the 1957 Form 301. In that connection Tidewater counsel, initially agreed that the company itself would make a study of its own records and would later present more accurate data with respect to jurisdictional sales volumes and revenues. However, at a subsequent hearing session Tidewater counsel stated that it had not been able to make such a study because the problem was a difficult one, requiring a great deal of time and effort. Tidewater counsel then stated that the company did not believe there was "enough substantial variation between what Mr. Soyster [37] has used and what might be the absolute ultimate correct item so that it would affect anything."

There then occurred this colloquy:

> Presiding Examiner . . . I take it that what you are saying now is that on more mature reflection and study you have decided that what the Staff did was not so bad after all, and that there is not really any significant discrepancy?
>
> Mr. Woodfin: Some changes were made with respect to Louisiana figures. What prompted my statement in the earlier hearing was the fact that we had done a rather hurried job in preparing the 301, and I was not prepared on the basis of the 301 to say those are the sales. But it appears that we had done probably a better job than we had thought we had done. But there is not enough difference to argue about any overall picture here, Mr. Examiner, I don't believe. (29:4391-4393)

Under the circumstances, the following considerations appear to be controlling here:

(1) Tidewater itself first injected a 1957 cost-of-service into the instant proceeding, and this change to a 1957 test year was, of course, beneficial to Tidewater since it reflected a more recent and a higher cost-of-service.

(2) The information as to the 1957 jurisdictional volumes and revenues was peculiarly in the possession of Tidewater itself, and not with the other parties.

(3) The very controversy which Tidewater counsel had raised at such length in connection with the 1955 cost studies, with respect to the accuracy of the Staff's jurisdictional volume figures obtained from Tidewater's 1955 Form 301, highlighted the importance of presenting for the record the precise figures as to the company's jurisdictional volumes and revenues. Under these circumstances, the burden was on Tidewater itself to see to it that the correct

[37] The staff witness.

figures as to 1957 jurisdictional volumes and revenues were presented for the record when the change was made to a 1957 test year.

(4) Although Tidewater devotes a great deal of time and energy toward establishing in its reply brief that the Form 301 figures are not properly useable for this particular purpose, no suggestion is made by Tidewater as to the allegedly correct 1957 jurisdictional volume and revenue figures, and it is nowhere suggested in the Tidewater briefs that the "correct" 1957 data would produce a lower unit revenue figure for jurisdictional gas than was derived by using the Form 301 data.

(5) In view of the circumstances outlined above, since Tidewater has presented nothing to the contrary, it seems entirely reasonable to assume that the declaration by Tidewater counsel that the 1955 Form 301 data did not reflect such a significant variation from the "absolute ultimate correct" data as to cause any serious problem, is equally applicable to the data presented by Staff and intervenors from the company's 1957 Form 301 filing.

Finally, although it is true that Tidewater's 1957 Form 301 was not made a part of the record as evidence in the instant proceeding, administrative notice will here be taken of this data. If it should later be shown that, unlike the 1955 Form 301 information, the 1957 filing contains truly significant errors, Tidewater may request an opportunity to make the correct data a part of the record.

Rates

Tidewater's rates which were charged for jurisdictional gas sold under rate schedules in effect during the 1957 test year yielded an average revenue of 14.5 cents per Mcf.[38] Since it has here been concluded that Tidewater's jurisdictional unit cost of service, based upon the test year 1957, amounted to 11.45 cents per Mcf, it would appear that Tidewater's jurisdictional revenues for 1957 were excessive by $2,160,464.[39]

The Commission, however, has made it clear in its *Phillips* decision, *supra*, in its Statement of General Policy No. 61–1, and in numerous other orders issued since that time, that its intent and policy is to fix just and reasonable rates for producers on an area basis rather than on an individual company basis. Under these circumstances, the determination under Section 5(a) of just and reasonable rates for Tidewater's jurisdictional sales in general, for the future, will have to await the establishment by the Commission of area rates for the producing areas in which Tidewater operates. Accordingly, the Examiner has no choice but to terminate the pending Section 5(a) proceeding against Tidewater in Docket G–13310.

This impediment, however, does not apply to the Section 4(e) rate increase dockets involved in the instant proceeding. In spite of its announced area rate policy, the Commission in the *Phillips* case itself, and in numerous other orders issued since that time, has disposed of Sec. 4(e) proceedings on the basis of individual company cost-of-service presentations where the case was tried on that basis and was ready for disposition prior to the Commission's announcement of its area price policy.[40] The instant Tidewater proceeding falls into the same category, and accordingly the Sec. 4(e) dockets here involved

[38] Based upon data in Tidewater's 1957 Form 301.

[39] Derived by multiplying the 1957 jurisdictional sales volume, obtained from the Form 301, by the difference between 1957 average jurisdictional revenue and jurisdictional unit cost as here determined.

[40] For example, see Order Accepting Offer of Settlement, *In the Matter of H. L. Hawkins and H. L. Hawkins, Jr., et al.*, Docket Nos. G–12306, *et al.* (issued April 14, 1961) 25 FPC 747; Order Fixing Just and Reasonable Rates, *In the Matter of Alfred C. Glassell, Jr., et al.*, Docket No. G–9278 (issued June 1, 1961), 25 FPC 1071.

may be disposed of on the basis of the cost-of-service determination made herein.

Under those dockets Tidewater in 1957 collected $1,824,444 of increased charges subject to refund. Since it has here been determined that Tidewater's total jurisdictional revenues in 1957 actually exceeded its jursidictional cost of service by over $2 million, no justification has been shown for approving such Section 4(e) rate increases. It is accordingly concluded that such increased rates should be disallowed and that all increased charges collected under such Section 4(e) rate filings should be refunded.

Findings and Conclusions

Upon consideration of the entire record in this proceeding, the evidence adduced and the briefs filed, the Presiding Examiner finds and concludes, in addition to the findings and conclusions hereinbefore stated, that

(1) The jurisdictional unit cost of service determined for Tidewater in this proceeding, based upon the test year 1957, is 11.45¢ per Mcf.

(2) Tidewater's jurisdictional revenues for the year 1957 were excessive by $2,160,464.

(3) Tidewater accordingly has not sustained the burden of establishing that it is entitled to the rate increases proposed in the instant consolidated Sec. 4(e) dockets.

(4) In view of the Commission's expressed policy to fix just and reasonable rates for producers on an area basis, rather than on an individual company basis, Tidewater's rates for the future cannot be fixed under Sec. 5(a) of the Act on the record made in the instant proceeding.

Order

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal, or upon its own motion as provided in the Commission's Rules of Practice and Procedure, that:

(A) Tidewater's proposed increased rates in the instant consolidated Sec. 4(e) dockets are hereby denied—being the proposed increased rates filed as Supplement No. 3 to its FPC Gas Rate Schedule No. 34, Supplements Nos. 10, 12 and 14 to its Gas Rate Schedule No. 18. Supplements Nos. 8, 10 and 11 to its Gas Rate Schedule No. 5, Supplements Nos. 5 and 6 to its Gas Rate Schedule No. 24, Supplements Nos. 1 and 2 to its Gas Rate Schedule No. 25, Supplements Nos. 3 and 4 to its Gas Rate Schedule No. 26, Supplement No. 9 to its Gas Rate Schedule No. 49, and Supplement No. 9 to its Gas Rate Schedule No. 37.

(B) Tidewater shall, within forty-five (45) days from the date of issuance of this initial decision, refund to its customer companies, with interest at the rate of 6 percent per annum, the difference between the amounts collected under the said Supplements to the above listed Gas Rate Schedules, and the rates and charges due and payable under said Rate Schedules prior to the filing and suspension of the increased rates proposed in the said Supplements; and Tidewater shall bear the costs of such refunds.

(C) Tidewater shall, within sixty (60) days of the date of issuance of this initial decision, report to the Commission in writing and under oath the details of its calculations resulting in refunds ordered pursuant to paragraph (B) above, together with copies of releases from its customer companies with respect to such refunds.

(D) Upon satisfactory compliance by Tidewater with the refund requirements of this initial decision and order, the proceedings in the instant consolidated Sec. 4(e) dockets shall be terminated.

(E) The instant Sec. 5(a) proceeding in Docket No. G–13310 is hereby terminated.

JOSEPH ZWERDLING,
Presiding Examiner.

APPENDIX A

Table 1

TIDEWATER OIL COMPANY

Southern and Central Divisions, 1957

Summary of Tidewater's 1957 jurisdictional cost of service [1]

		Cost per Mcf
(1)	Total on-lease expense	[2] $0.0142
(2)	Off-lease expense	[3] 0.0076
(3)	Exploration expense	[4] 0.0559
(4)	Production taxes	[5] 0.0096
(5)	Total revenue deductions	0.0873
(6)	Return on rate base at 10%	[6] 0.0272
(7)	Total gas cost of service	0.1145

[1] Exh. 180, adjusted to reflect the following changes: (a) elimination of Gasoline and Cycling Plan Expenses and Investment; (b) recomputation of allocation factor for exploration and development costs under the Commission's Phillips modified Btu method; (c) recomputation of working capital allowance; (d) employment of year-end rate base; (e) allowance of a 10% rate of return.
[2] Exhibit 180, Schedule 2.
[3] Table 2.
[4] Table 4.
[5] Exhibit 180, Schedule 15.
[6] Table 7.

APPENDIX A

Table 2

Tidewater Oil Company, Southern and Central Divisions, 1957

Allocation of total off-lease expenses to liquids and gas, relative cost method [1]

Off-lease expenses	Total (A)	Allocated to gas	
		Percent of total (B)	Amount (A)×(B) (C)
(1) Other operating expenses and unassigned taxes	$2,009,232	11.35	[2] $228,048
(2) General and administrative expense	1,741,021	11.35	[2] 197,606
(3) Estimated FPC expense	300,000	100.00	300,000
(4) Total off-lease expenses			725,654
(5) Total off-lease expenses per Mcf $725,654÷95,221,474 Mcf			0.0076

[1] Recomputation of Exhibit 180, Schedule 3, with line (4), "Gasoline and Cycling Plant Expenses," omitted.
[2] Average of percent of on-lease expenses excluding depreciation and depletion allocated to gas (3.17%) (Schedule 10, Exhibit 180), on-lease net investment allocated to gas (19.50%) (Schedule 6, Exhibit 180) and on-lease gross investment allocated to gas (11.38%) (Schedule 8, Exhibit 180).

APPENDIX A

Table 3

Tidewater Oil Company, Southern and Central Divisions, 1957

Allocation factor for exploration and development costs, modified Btu method [1]

	Volumes (Mcf or Bbl) (A)	Average weighted Btu ratio[2] (Millions) (B)	Total Btu's (Millions) (C)	Application of economic factor (D)	Adjusted total Btu's (Millions) (E)	Percent (F)
Gas						
(1) Normalized gas sales	[3] 109,721,000	1.088	119,376,000		119,376,000	24.17
(2) Royalties	[4] 2,076,298	1.088	2,259,000		2,259,000	.46
Liquids						
(3) Liquid sales (excluding plant liquids)	[4] 20,860,436	5.628	117,402,000	3	352,206,000	71.32
(4) Plant liquids	[5] 2,854,787	5.628	16,067,000		16,067,000	3.25
(5) Royalties	[4] 235,673	5.576	1,314,000	3	3,942,000	.80
(6) Total					493,850,000	100.00

[1] Method adopted by the Federal Power Commission in Opinion No. 338, In the Matter of Phillip Petroleum Company, Docket Nos. G-1148, *et al.*
[2] Derived from Exhibit 129, Schedule 5.
[3] Normalized Volumes shown in Exhibit 150, Schedule 15.
[4] Exhibit 129, Schedule 5.
[5] Appendix 3, Tidewater's Initial Brief, Schedule 2, Page 6, Lines 4 and 5.

APPENDIX A

Table 4

TIDEWATER OIL COMPANY

Southern and Central Divisions, 1957

Exploration and development expenses allocated to gas

(1) Total exploration and development expense	[1] $25,378,704
(2) Percent allocated to gas	[2] 24.17%
(3) Amount allocated to gas (2)×(1)	$6,134,033
(4) Amount per Mcf ($6,134,033÷109,721,000 Mcf [3])	$0.0559

[1] Exhibit 128, Schedule 1, Page 9.
[2] Table 3.
[3] Normalized Gas Production.

Exhibit 150 Schedule 15.

APPENDIX A

Table 5

TIDEWATER OIL COMPANY

Southern and Central Divisions, 1957

Allocation of off-lease net investment [1]

	Amount to be allocated (A)	Allocated to gas	
		Percent (B)	Amount (C)
(1) Total production department Off-lease net investment (eliminating gasoline and cycling plant)	$890,338	[2] 15.44	$137,468
Other off-lease net investment including working capital			
(2) Cash	[3] 4,001,784	[4] 16.66	666,697
(3) Materials and supplies	9,034,151	11.59	1,047,058
(4) Exploration department investment	17,201,862	[5] 24.17	4,157,690
(5) Total off-lease net investment	31,128,135		6,008,913

[1] Recomputation of Exhibit 180, Schedule 7, with Gasoline and Cycling Plant investment (Schedule 7 Line 1) eliminated and with revised allocation factors.
[2] Exhibit 180, Schedule 7, Line 8, Column (C).
[3] Staff Initial Brief, Appendix E:

Production department working capital (Col. 2)	$1,700,097
Exploration department working capital (Col. 3)	2,301,687
Total	4,001,784

[4] Table 6.
[5] Table 3. Factor based on normalized gas sales.

APPENDIX A

Table 6

TIDEWATER OIL COMPANY

Southern and Central Divisions, 1957

Derivation factor for allocating cash [1]

	Total expense (A)	Amount allocated to gas (B)
(1) Estimated FPC expense	$300,000	$300,000
(2) Other operating expenses and unassigned taxes	2,009,232	228,048
(3) General and administrative expense	1,741,021	197,606
(4) Exploration expenses excluding amortization of undeveloped leaseholds	[2] 18,413,499	[3] 4,450,543
(5) Total off-lease cash-involving expenses	22,463,752	5,176,197
(6) On-lease expenses other than depreciation and depletion	11,978,090	380,093
(7) Production taxes	4,396,169	912,412
(8) Total cash-involving expenses	38,838,011	6,468,702
(9) Amount allocated to gas as a percent of total (8B) ÷ (8A)		16.66

[1] Recomputation of Exhibit 180, Schedule 9, Eliminating Plant Operating Expenses (Line 1 of Schedule 9) and with Revised Allocation Factors.
[2] Includes Development Dry Hole Losses.
[3] Column (A) Multiplied by 24.17% (Table 3, Line 1, Column (F)).

APPENDIX A

Table 7

TIDEWATER OIL COMPANY

Southern and Central Divisions, 1957

Gas rate base and return at 10%

(1)	On-lease net investment as of Dec. 31, 1957	[1] $23,815,419
(2)	Off-lease net investment as of Dec. 31, 1957	[2] 6,008,913
(3)	Total	29,824,332
(4)	Return at 10%	$2,982,433
(5)	Return per Mcf ($2,982,433÷Normalized Production of 109,721,000 Mcf)[3]	$0.0272

[1] Exhibit 180, Schedule 6.
[2] Table 5.
[3] Exhibit 150, Schedule 15.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

TRANSWESTERN PIPELINE COMPANY, DOCKET NO. CP62-185

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 15, 1962)

On February 9, 1962, Transwestern Pipeline Company (Applicant) filed in Docket No. CP62-185 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing a direct interruptible sale of natural gas to Climax Chemical Company (Climax) in Lea County, New Mexico, all as more fully set forth in the application.

The proposed sale would be made from Applicant's 10-inch Monument lateral in daily volumes of up to 2,000 Mcf of gas pursuant to an agreement between the parties dated January 24, 1962. The contract is for one year with a provision for continuation of service on a year-to-year basis. The gas will be used for fuel in the Climax plant.

Applicant was granted temporary authorization to render the proposed service on February 27, 1962.

Pursuant to due notice, a public hearing was held in Washington, D. C., on June 5, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, Transwestern Pipeline Company, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of August 10, 1959, in Docket No. G-14871, *et al.* (22 FPC 391).

(2) The proposed sale and delivery of natural gas hereinbefore described, as more fully described in the application in this proceeding, are to be made in interstate commerce, subject to the jurisdiction of the Commission, and are, therefore, subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The proposed sale and delivery of natural gas by Applicant, together with any facilities necessary therefor, are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of such Regulations.

(6) The sale hereinafter authorized should be limited to 2,000 Mcf of gas per day.

(7) A request by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Transwestern Pipeline Company, to sell and deliver up to 2,000 Mcf of interruptible gas per day to Climax Chemical Company, and to construct any facilities necessary therefor, as hereinbefore described, all as more fully described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of such Regulations.

Before Commissioners: Joseph C. Swidler, Chairman, Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

J. RAY McDERMOTT & COMPANY, INC., *ET AL.*, DOCKET NO. G-19873

ORDER DENYING MOTION TO TERMINATE PROCEEDING IN PART

(Issued June 18, 1962)

On September 30, 1959, J. Ray McDermott & Company, Inc., *et al.*, (McDermott) filed two notices of change in its effective rate schedules relating to gas produced in the Plymouth and W. Callaboose Fields, San Patricio County, Texas, and the Red Fish Bay Field, Nueces County, Texas, and sold to Tennessee Gas Transmission Company. By order issued October 23, 1959, said tenders, which would increase the level of rate from 12.12268¢ to 15.0952¢ per Mcf, were designated as Supplement No. 7 to McDermott's FPC Gas Rate Schedules Nos. 7 and 5, respectively, and were suspended until April 1, 1960, and thereafter until each is made effective in the manner prescribed by the Natural Gas Act. Upon proper motion said increased rates became effective as of that date subject to further orders in this proceeding.

On January 9, 1961, the Estate of Herman F. Heep and Mrs. Minnie Belle Heep (Heep) [1] tendered a motion seeking modification of the aforesaid suspension order issued October 23, 1959, as to their interests to provide that the suspension of that portion of the *rate increase* which does not exceed 14¢ per Mcf be terminated. In support of the motion, Heep states that the Commission's *Statement of General Policy No. 61–1*, 24 FPC 818, establishes 14¢ per Mcf as the area price for the two counties here involved; and requests that the Commission's order issued October 23, 1959, suspending the entire rate increase, be modified so that the suspension of that portion of the rate increase which does not exceed 14¢ per Mcf be terminated effective as of the date of receipt by the Commission of said motion, and that Heep be allowed to collect such part of the increased rate not exceeding 14¢ per Mcf unconditionally and without obligation to refund.

As we have stated before, the rate levels shown in the aforementioned *Statement of General Policy* are merely 'to serve as a guide' in determining 'just and reasonable' rates. They are not determinative of the 'just and reasonable' rates for the various areas. Neither are they to be considered as floor rates for sales made in the various areas. In fact, it may result that, based on evidence adduced, the just and reasonable rate for the particular sale of gas may be below that set out in our Statement of General Policy for the producing area wherein the sale is made. *Humble Oil & Refining Company*, Docket No. G–17144, Order Denying Motion to Make Effective Without Obligation to Refund a Portion of Proposed Increased Rates, issued June 19, 1961, 25 FPC 1173, and *S. W. Richardson*, Docket No. RI61–280, Order Denying Motion for Modification of Order Suspending Increased Rate, issued June 19, 1961, 25 FPC 1177.

The Commission finds:

That for the reasons heretofore stated, it is in the public interest and necessary in the proper enforcement of the Natural Gas Act, that Heep's aforesaid motion to partially terminate this proceeding be denied.

The Commission orders:

Heep's motion to terminate this proceeding insofar as the proceeding pertains to that portion of the increased rate not in excess of 14¢ per Mcf is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

J. RAY McDERMOTT & COMPANY, INC., *ET AL.*, DOCKET NO. RI60–383

ORDER DENYING MOTION TO TERMINATE SUSPENSION PROCEEDING IN PART

(Issued June 18, 1962)

On May 12, 1960, J. Ray McDermott & Company, Inc., *et al.*, (McDermott) filed a notice of change in its effective rate schedule relating to gas produced in the Mustang and Red Fish Bay Fields, Nueces and San Patricio Counties, Texas, and sold to United Gas Pipe Line Company. By order issued herein on June 8, 1960, said tender, which would increase the level of rate from 12.66¢ to 14.8¢ per Mcf, was designated as Supplement No. 8 to McDermott's FPC Gas Rate Schedule No. 8 and was suspended until November 12, 1960, and there-

[1] McDermott by letter dated May 24, 1960, advised the Commission that the Estate and Mrs. Heep each retain 7.29165% of interest in the production sold pursuant to its FPC Gas Rate Schedule No. 5 and 25% pursuant to its FPC Gas Rate Schedule No. 7.

after until it is made effective in the manner prescribed by the Natural Gas Act.

On January 9, 1961, the Estate of Herman F. Heep and Mrs. Minnie Belle Heep (Heep) [1] filed a motion seeking modification of the aforementioned suspension order issued June 8, 1960, as to their interests, to provide that the suspension of that portion of the rate increase which does not exceed 14¢ per Mcf be terminated. In support of their motion, Heep states that the Commission's *Statement of General Policy No. 61–1*, as amended, establishes 14¢ per Mcf as the area price for the two counties involved; and requests that the Commission's order issued June 8, 1960, suspending the entire rate increase filed by McDermott, be modified so that the suspension of that portion of the rate increase which does not exceed 14¢ per Mcf be terminated effective as of the date of receipt by the Commission of said motion, and that Heep be allowed to collect such part of the increased rate not exceeding 14¢ per Mcf unconditionally and without obligation to refund.

As we have stated before, the rate levels set out in our *Statement of General Policy No. 61–1* are merely 'to serve as a guide' in determining 'just and reasonable' rates. They are not determinative of the 'just and reasonable' rates for the various areas. Neither are they to be considered as floor rates for sales made in the various areas. In fact, it may result that, based on evidence adduced, the just and reasonable rate for the particular sale of gas may be below that set out in our Statement of General Policy for the producing area wherein the sale is made. *Humble Oil & Refining Company*, Docket No. G–17144, Order Denying Motion to Make Effective Without Obligation to Refund a Portion of Proposed Increased Rates, issued June 19, 1961, 25 FPC 1173, and *S. W. Richardson*, Docket No. RI61–280, Order Denying Motion for Modification of Order Suspending Increased Rate, issued June 19, 1961, 25 FPC 1177.

The Commission finds:

For the reasons heretofore stated, it is in the public interest and necessary in the proper enforcement of the Natural Gas Act that Heep's aforesaid motion to partially terminate this proceeding be denied.

The Commission orders:

Heep's motion to terminate this proceeding insofar as the proceeding pertains to that portion of the increased rate not in excess of 14¢ per Mcf is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

AMENDMENT OF PART 1, RULES OF PRACTICE AND PROCEDURE, RELATING TO INTERVENTION AND APPLICATIONS FOR REHEARING AND PART 157, REGULATIONS UNDER THE NATURAL GAS ACT, RELATING TO TEMPORARY SERVICE BY PRODUCERS, DOCKET NO. R–219

ORDER NO. 251

MISCELLANEOUS AMENDMENTS

(Issued June 18, 1962) *

The Commission has under consideration in this proceeding the amendment of its rules of practice relating to intervention [18 CFR 1.8] and applications

[1] Party sellers under the rate schedule involved in this proceeding.

* Published in the Federal Register on June 19, 1962, (27 F.R. 5766)

for rehearing [18 CFR 1.34] and its regulations under the Natural Gas Act with respect to authorizations for temporary service by independent producers [18 CFR 157.28]. The amendments are unrelated.

1. The Commission, in the past, has permitted persons or municipalities engaged in local distribution of natural gas to intervene in both certificate and rate proceedings for the purpose of obtaining, pursuant to section 7 (a) of the Natural Gas Act, an order from the Commission directing the applicant or respondent pipeline company to interconnect its facilities with and sell natural gas to the municipality or distribution company. Part 156 of the Regulations Under the Natural Gas Act [18 CFR, Part 156] sets forth the requirements with which applicants (as distinguished from those petitioning for intervention) for a section 7 (a) order must comply. Obviously, the Commission needs the same information to determine whether such an order should be issued irrespective of whether the request is made by application under Part 156 or in a petition to intervene. Accordingly, we are amending the intervention rule to require petitioners thereunder to comply with Part 156 when the purpose of the requested intervention is to obtain a section 7 (a) order.

2. Section 1.34 of the rules of practice sets out the requirements to be followed in making applications for rehearing pursuant to sections 313 (a) of the Federal Power Act and 19 (a) of the Natural Gas Act, respectively. The rule makes no provision for the filing of an answer to such an application and we are not now providing for one.

We believe, however, that if rehearing is granted a pleading in the nature of an answer would serve to more clearly define the issues and enable parties and staff counsel to present their positions on the issues upon which rehearing has been granted to the Commission. We are therefore amending section 1.34 to provide for such a pleading.

3. Section 157.28 of the Regulations Under the Natural Gas Act provide a method whereby applications for authority to institute temporary service by independent producers can be processed expeditiously. The benefits of that section are not available under the existing rule "with respect to service proposed to commence more than 30 days from the date of the filing of the statement" required to be filed by the section.

It has been brought to our attention that the pipeline purchaser will often not commence construction of its connecting facilities until the temporary authorization to commence service has been issued and accepted by the producer. Unless the construction required is extremely limited, the time necessary for acceptance and construction can well exceed the thirty-day limitation of the rules. Since the objective of the temporary authorization is to relieve the producer of possible hardship we believe that there should be some time limitation. We are therefore amending the rule to enlarge the limitation to 90 days from the date the authorization is issued by the Commission.

If the applicant in a particular case has reason to believe that a period in excess of 90 days is required he should furnish information in support of such increased period at the time the request for temporary authorization is filed.

For the reasons set forth above, the Commission *finds:*

(1) The amendments ordered herein are appropriate and necessary for carrying out the provisions of the Federal Power and Natural Gas Acts.

(2) The amendments to Part 1, hereinafter adopted pertain to matters of practice and procedure which do not require notice or hearing under section 4 (a) of the Administrative Procedure Act.

(3) Although the amendment to section 157.28 might be construed as involving a matter of substance, prior notice thereof is unnecessary since it relaxes, in effect, the restrictions of the existing rule and provides by general order

requirements which could be imposed by individual order applicable only to the request for temporary authorization particularly involved.

(4) Good cause exists for making the amendments effective as herein ordered. *The Commission*, acting pursuant to sections 308, 309, and 313 of the Federal Power Act (49 Stat. 858, 859, 860, 16 U.S.C. 825g, 825h, 825*l*) and sections 7, 15, 16, and 19 of the Natural Gas Act (56 Stat. 83, 52 Stat. 83, 52 Stat. 829, 830, 831, 15 U.S.C. 717f, 717n, 717o, 717r) *orders:*

(A) Part 1, Rules of Practice and Procedure, Chapter I of Title 18 of the Code of Federal Regulations, is amended as follows:

1. In § 1.8, subsection (c) is amended by adding a proviso at the end of the first sentence and revising the second sentence, to read as follows:

"(c) *Form and contents of petitions.* Petitions to intervene shall set out clearly and concisely the facts from which the nature of the petitioner's alleged right or interest can be determined, the grounds of the proposed intervention, and the position of the petitioner in the proceeding, so as fully and completely to advise the parties and the Commission as to the specific issues of fact or law to be raised or controverted, by admitting, denying or otherwise answering, specifically and in detail, each material allegation of fact or law asserted in the proceeding, and citing by appropriate reference the statutory provisions or other authority relied on: *Provided*, That where the purpose of the proposed intervention is to obtain an allocation of natural gas for sale and distribution by a person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public, the petition shall comply with the requirements of Part 156 of this chapter (i.e., Regulations Under the Natural Gas Act). Such petitions shall in other respects comply with the requirements of §§ 1.15 to 1.17, inclusive."

[Authority: Secs. 15, 16, 52 Stat. 829, 830, sec. 7, 56 Stat. 83, 15 U.S.C. 717f, 717n, 717o.]

2. In § 1.34, add a new subsection (d) to read as follows:

"(d) *Response.* No answers to petitions for rehearing will be entertained by the Commission. If, and to the extent, however that rehearing is granted by the Commission, a response in the nature of an answer may be filed by any party or staff counsel within 15 days after the issuance of the order granting rehearing. Such response shall be confined to the issues upon which rehearing has been granted, and shall be served by the proponent upon all parties to the proceeding or their attorneys of record. All such responses shall in all other respects conform to the requirements of §§ 1.15 to 1.17, inclusive."

[Authority: Secs. 308, 309, and 313, 49 Stat. 858, 859, 860, 16 U.S.C. 825g, 825h, 825*l*; secs. 15, 16, and 19, 52 Stat. 829, 830, 831, 15 U.S.C. 717n, 717o, 717r.]

(B) In § 157.28 of Part 157, Regulations Under the Natural Gas Act, Chapter I of Title 18 of the Code of Federal Regulations, paragraph (a) is amended to read as follows:

"(a) It does not apply to termination of any sale or transportation or with respect to service proposed to commence more than 90 days from the date on which the temporary authorization is issued by the Commission unless otherwise ordered for good cause shown."

[Authority: Sec. 16, 52 Stat. 830, sec. 7, 56 Stat. 83, 15 U.S.C. 717f, 717o.]

(C) The amendments prescribed by ordering clause (A) herein are effective upon the issuance of this order.

(D) The amendment to § 157.28 prescribed in ordering clause (B) herein shall be effective July 15, 1962.

(E) The Secretary shall cause prompt publication of this order to be made in the Federal Register.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

UNITED GAS PIPE LINE COMPANY AND TENNESSEE GAS TRANSMISSION COMPANY, DOCKET NO. CP62-213

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND ACCEPTING RATE SCHEDULE FOR FILING

(Issued June 19, 1962)

On March 14, 1962, United Gas Pipe Line Company (United) and Tennessee Gas Transmission Company (Tennessee) (sometimes hereinafter referred to jointly as Applicants) filed in Docket No. CP62-213 a joint application pursuant to Section 7 (c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing Tennessee to deliver natural gas to United up to and including March 31, 1963, in return for equivalent volumes of natural gas delivered by United to Tennessee during the period January 16 to January 29, 1962.

Applicants state that United made the temporary delivery of natural gas to Tennessee as a result of an emergency existing on Tennessee's system and that Applicants seek herein authorization permitting Tennessee to return such gas up to and including March 31, 1963.

No new facilities will be required to make the proposed deliveries.

On February 15, 1962, United filed an agreement, dated January 26, 1962, between Applicants, providing for the subject exchange, as its proposed Rate Schedule X-13 to its FPC Gas Tariff, Original Volume No. 2.

Pursuant to due notice, a public hearing was held in Washington, D. C., on June 7, 1962, respecting the matters involved in and the issues presented by the joint application herein. No petition to intervene or protest to the granting of the application has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, United Gas Pipe Line Company, a Delaware corporation having its principal place of business in Shreveport, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of January 20, 1942, in Docket No. G-216 (3 FPC 2).

(2) Applicant, Tennessee Gas Transmission Company, a Delaware corporation having its principal place of business in Houston, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of July 12, 1947, in Docket No. G-910 (6 FPC 777).

(3) The return deliveries of emergency gas by Tennessee to United hereinbefore described, as more fully described in the application in this proceeding,

are to be made in interstate commerce, subject to the jurisdiction of the Commission and such deliveries by Tennessee are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(4) Applicants are able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(5) The proposed return deliveries of emergency gas by Tennessee to United are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(6) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (c) (3) and (e) of Section 157.20 of such Regulations.

(7) The agreement, dated January 26, 1962, filed on February 15, 1962, by United should be accepted for filing as Rate Schedule X–13 to United's FPC Gas Tariff, Original Volume No. 2, to become effective on the date this order issues.

(8) The certificate hereinafter issued should be conditioned upon Tennessee filing, in accordance with the requirements of Part 154 of the Commission's Regulations under the Natural Gas Act, a rate schedule similar to that filed by United as United's Rate Schedule X–13.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued jointly to Applicants, United Gas Pipe Line Company and Tennessee Gas Transmission Company, authorizing Tennessee to deliver and return to United the emergency gas delivered by United at any time up to and including March 31, 1963, as hereinbefore described, all as more fully described in the joint application herein, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (c) (3) and (e) of Section 157.20 of such Regulations.

(C) The agreement, dated January 26, 1962, filed on February 15, 1962, by United is hereby accepted for filing as Rate Schedule X–13 to United's FPC Gas Tariff, Original Volume No. 2, to become effective on the date this order issues.

(D) The certificate issued by paragraph (A) above is hereby conditioned upon Tennessee filing, in accordance with the requirements of Part 154 of the Commission's Regulations under the Natural Gas Act, a rate schedule similar to that filed by United as United's Rate Schedule X–13.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

EL PASO NATURAL GAS COMPANY, DOCKET NO. CP62-64

FINDING AND ORDER AMENDING ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 20, 1962)

On April 23, 1962, El Paso Natural Gas Company (Petitioner) filed in Docket No. CP62-64 a petition to amend the certificate order in said docket issued December 12, 1961, 26 FPC 836, by authorizing the construction and operation of three additional lateral pipelines to sell and deliver natural gas to The Washington Water Power Company for resale and distribution in Rosalia, St. John, and LaCrosse, Washington, all as more fully set forth in the petition.

Petitioner has already installed one lateral line pursuant to the authorization granted in the instant docket and presently has pending requests for four more lines including those which are the subject of the present petition. The facilities required to serve the three communities herein are 2.0 miles of 2⅜" O.D. pipeline for Rosalia at an estimated cost of $23,054, 1.3 miles of 2⅜" O.D. pipeline for St. John at an estimated cost of $15,179, and 0.9 miles of 2⅜" O.D. pipeline for LaCrosse at an estimated cost of $10,679. The facilities will be constructed along the transmission system of Pacific Gas Transmission Company.

Petitioner does not seek authorization to construct and operate facilities in excess of the cost and volumetric limitations set forth in the order of December 12, 1961.

Notice of the petition was published in the Federal Register on May 18, 1962 (27 FR 4744). No protest, request for hearing, or petition to intervene has been received.

The Commission finds:

It is appropriate in carrying out the provisions of the Natural Gas Act and required by the public convenience and necessity that the certificate order issued December 12, 1961, in Docket No. CP62-64 should be amended to authorize the construction and operation of additional facilities as hereinbefore described and as more fully described in the petition herein.

The Commission orders:

(A) The order issued on December 12, 1961, in Docket No. CP62-64 be and the same is hereby amended to authorize the construction and operation of additional facilities as hereinbefore described and as more fully described in the petition herein.

(2) In all other respects, including cost and volumetric limitations, the order issued December 12, 1961, shall remain in full force and effect.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

UNION ELECTRIC COMPANY, DOCKET NO. E-6927

ORDER DENYING APPLICATION FOR REHEARING

(Issued June 20, 1962)

On May 21, 1962, Union Electric Company filed application for rehearing of the Commission's Opinion No. 356 and Order Upon a Declaration of Intention, issued April 19, 1962, in the above-entitled proceeding [27 FPC 801]. The Presiding Examiner at the original hearing had found that the proposed Taum Sauk project in the State of Missouri would be capable of affecting, and would, at times, affect the navigable capacity of the Black River which is a navigable waterway of the United States, and therefore, was required to be licensed under the Federal Power Act. The Commission adopted his findings and conclusions in this regard. In addition, the Examiner found that the proposed project will be constructed, operated and maintained for the development of power to supply markets outside the State of Missouri, thereby affecting the interests of interstate commerce. The Commission adopted this finding also and held that the development, transmission and utilization of this power in interstate commerce will have such an effect upon the interests of interstate commerce that a hydroelectric project proposing to use the Nation's water resources for this purpose is required to be licensed under the Federal Power Act.

In Opinion No. 356, the Commission held that it had the duty under the Federal Power Act, when the use of the Nation's water resources is proposed for hydroelectric power development, to assure that the most beneficial and comprehensive use of those resources is achieved and protected in the interests of the Nation as a whole. When the interests of interstate commerce will be affected by such a project, even if navigation were not affected, the Commission held that the same duty applied.

The Commission finds:

The grounds for rehearing contained in the application for rehearing set forth no new facts or principles of law which were not fully considered by the Commission when it issued its opinion and order on April 19, 1962, or which, having now been considered, warrant any modification of the said opinion and order.

The Commission orders:

The above-mentioned application for rehearing of the Commission's Opinion No. 356 and Order issued April 19, 1962 in this proceeding is hereby denied.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

PACIFIC POWER & LIGHT COMPANY, PROJECT NO. 2082

ORDER APPROVING PROJECT EXHIBITS AND ADJUSTING ANNUAL CHARGES

(Issued June 21, 1962)

On June 14, 1960, Pacific Power & Light Company, licensee for major Project No. 2082, filed for Commission approval Exhibits J and K showing the project area and boundary of the existing developments of the project.

The effect of approval of Exhibit K will be to establish the project area and will result in an increase of 38.08 acres of lands of the United States occupied by the project under license and an increase of $76.16 in the amount of annual charges under the Federal Power Act.

The annual charge for the use of United States lands presently included in the license is $456.64. Inclusion of the additional lands in the project will increase the charge to $532.80, effective as of March 1, 1956, the date on which the existing developments occupling such lands were included in the license.

The Commission finds:

(1) Exhibit J (FPC No. 2082–120) and Exhibit K (FPC No. 2082–121 through–125) conform to the Commission's rules and regulations and should be approved as part of the license for the project, and Exhibit J (FPC No. 2082–77), now part of the license and which is superseded, should be eliminated from the license.

(2) The increased amount of annual charges to be paid under the license for the purpose of recompensing the United States for the use, occupancy, and enjoyment of its lands, exclusive of those lands used for transmission-line right-of-way, is reasonable as hereinafter fixed and specified.

The Commission orders:

(A) The exhibits described in finding (1) above as conforming to the Commission's rules and regulations are approved as part of the license for the project, and the exhibit described in the same finding as being superseded is eliminated from the license for the project.

(B) Subparagraph (b) of Article 35 of the license is amended to read as follows:

(b) For the purpose of recompensing the United States for the use, occupancy, and enjoyment of its lands, exclusive of those used for transmission line right-of-way, $532.80, effective as of March 1, 1956.

(C) This order shall become final 30 days from the date of its issuance unless application for rehearing shall be filed as provided in Section 313 (a) of the Federal Power Act and failure to file such an application shall constitute acceptance of this order. In acknowledgment of the acceptance of this order, it shall be signed for the licensee and returned to the Commission within 60 days from the date of its issuance.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

FLORIDA GAS TRANSMISSION COMPANY, DOCKET NO. CP62–257

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 22, 1962)

On May 7, 1962, Florida Gas Transmission Company (Applicant) filed in Docket No. CP62–257 an application pursuant to Section 7(c) of the Natural Gas Act, for a certificate of public convenience and necessity seeking authorization to construct and operate approximately 0.2 mile of 2⅜-inch O.D. lateral pipeline extending from a point on its 20-inch mainline at a point near Holapaw, Osceola County, Florida, in a general southwesterly direction to a point adjacent to the hay drying plant of Cattle Marketers, Inc. (Marketers), together

with a meter and regulator station, and to sell and deliver natural gas to Marketers on a direct sale preferred interruptible basis, all as more fully set forth in the application.

The natural gas will be used by Marketers in its process of drying hay by means of a gas-fired continuous felt type drier.

It appears that Applicant has sufficient capacity to sell and deliver the natural gas requirements of Marketers without affecting its ability to continue present service to any existing customers on its interstate natural gas transmission system.

Applicant estimates that the average annual deliveries to Marketers will be approximately 275,000 M²btu. The cost of constructing the proposed facilities is $11,600 which cost will be paid by Marketers.

Pursuant to due notice, a public hearing was held in Washington, D. C., on June 19, 1962, respecting the matters involved in and the issues presented by the application in this proceeding. No protest or petition to intervene has been filed. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of the Commission's Rule of Practice and Procedure.

The Commission finds:

(1) Applicant, Florida Gas Transmission Company, a Delaware corporation having its principal place of business in St. Petersburg, Florida, is a "natural-gas company" within the meaning of the Natural Gas Act as successor in interest to Houston Texas Gas and Oil Corporation as provided by order of the Commission in Docket Nos. G–9262, *et al.*, issued on April 18, 1962.

(2) The facilities hereinbefore described, as more fully described in the application in this proceeding, are to be used in the transportation and delivery of natural gas in interstate commerce, subject to the jurisdiction of the Commission, as integral parts of Applicant's existing system, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

(4) The construction and operation of the facilities and the delivery of natural gas as proposed by Applicant herein are required by the public convenience and necessity and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (3), (c) (4) and (e) of Section 157.20 of such Regulations, and that the construction of the facilities authorized by this order should be completed and said facilities placed in actual operation within six months from the date on which this order issues.

(6) The volume of natural gas to be delivered by Applicant to Cattle Marketers, Inc. pursuant to the authorization hereinafter granted should be limited to not more than 275,000 M²Btu (Mcf at 1000 Btu per cubic foot) per year.

(7) A request during the public hearing by staff counsel for omission of the intermediate decision herein was unopposed by any party of record and, not

having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Florida Gas Transmission Company to construct and operate the facilities and to deliver natural gas as hereinbefore described, as more full described in the application in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (3), (c) (4) and (e) of Section 157.20 of such Regulations.

(C) The construction of the facilities authorized by this order shall be completed and said facilities placed in actual operation within six months from the date on which this order issues.

(D) The volume of natural gas to be delivered by Florida Gas Transmission Company to Cattle Marketers, Inc. under this authorization is hereby limited to not more than 275,000 M^2Btu (Mcf at 1000 Btu per cubic foot) per year.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

EL PASO NATURAL GAS COMPANY, DOCKET NOS. G–4769, G–12948, G–17929, AND RP60–3

ORDER AFFIRMING RULING OF PRESIDING EXAMINER

(Issued June 26, 1962)*

This matter is before us on appeal by the El Paso Natural Gas Company (El Paso) from the Presiding Examiner's ruling at the hearing on June 4, 1962, sustaining objections to El Paso's proposed rebuttal Exhibits Nos. 130 and 131 entitled, respectively "El Paso Natural Gas Company, Cost of Service Study—Docket No. RP60–3, 17 months ended December 31, 1961" and "El Paso Natural Gas Company, Cost of Service Study—Docket No. RP60–3, Calendar Year 1961, Adjusted for Known Changes," and to the proposed rebuttal testimony related thereto, and excluding said exhibits and striking said testimony from the record. The objections to the proposed testimony and exhibits, were filed by the California Public Utilities Commission, Southern California Gas Company and Southern Counties Gas Company, Pacific Gas and Electric Company, the City and County of San Francisco and the Commission Staff. Replies to these objections were filed by Washington Natural Gas Company, Northwest Natural Gas Company, Arizona Public Service Company and El Paso Natural Gas Company. The portion of the record pertinent to the issue herein involved has been certified to us by the Presiding Examiner.

We agree with the Presiding Examiner that the question presented here is governed by the Commission's order in *Texas Gas Transmission Corporation*, Docket No. RP61–15 [September 8, 1961, 26 FPC 479], wherein the Commission held:

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*Order issued August 15, 1962 denying reconsideration, 28 FPC 325. Petition for Review dismissed, El Paso Natural Gas Co. v. F.P.C. (CA5 No. 20041).

We believe that once a company has selected a test period either for use in settlement conferences or for presentation in a formal proceeding, the subsequent adoption of this same test period by the staff and the preparation of Staff's case in reliance thereon are matters affecting the public interest. In such circumstances, any unilateral departure from the selected test period must be supported by reasons of compelling nature. We ing test period must be supported by reasons of compelling nature. We do not believe that the facts of this particular case warrant such a unilateral departure.

We, therefore, find that the appeal by Commission Staff should be upheld, the ruling of the presiding examiner set aside, and that the testimony and exhibits admitted in evidence by the examiner should be stricken from the record of this proceeding.

The acceptance of the proposed testimony and exhibits would reopen these proceedings for the purpose of retrying Docket No. RP60–3 on the basis of the costs and revenues shown in Exhibits 130 and 131 for test periods different from that used by El Paso and the Commission staff in the proceedings in that docket. We do not believe this to be in the public interest. The public interest requires the orderly administration of regulation. This means, *inter alia*, that at some point in the regulatory process litigation must terminate. *Interstate Commerce Commission* v. *Jersey City*, 322 U.S. 503, 514; *El Paso Natural Gas Co.* v. *F.P.C.*, 281 F. 2d 567, 574.

The Commission orders:

The appeal of the El Paso Natural Gas Company from the Presiding Examiner's ruling of June 4, 1962, sustaining objections to Exhibits Nos. 130 and 131 and the testimony relating thereto and excluding said exhibits and striking said testimony from the record is hereby denied, and the Presiding Examiner's ruling thereon is hereby affirmed.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

SIERRA PACIFIC POWER COMPANY, DOCKET NO. E–7031

SUPPLEMENTAL ORDER AUTHORIZING THE ISSUANCE OF FIRST MORTGAGE BONDS

(Issued June 26, 1962)

By order issued June 14, 1962, 27 FPC 1252, in the above-entitled matter, the Commission authorized Sierra Pacific Power Company (Applicant) to issue and sell at competitive bidding $5,000,000 principal amount of First Mortgage Bonds, due 1992, subject to the provisions, among others, set forth in Paragraph (B) of that order, as follows:

(B) The proposed issuance and sale of Bonds at competitive bidding shall not be consummated until:

(i) Applicant shall have amended its application pursuant to the requirements of Section 34.2 (k) (3) of the Commission's Regulations under the Federal Power Act relating to compliance with competitive bidding requirements, and Section 34.2 (k) (4) of those Regulations relating to affiliation, and shall have either filed such amendments or shall have mailed them and advised the Commission by telephone and telegraph, as contemplated in Section 34.9 of the Regulations.

(ii) The Commission, by further order, shall have approved the price to be received by Applicant for the proposed issuance of Bonds and the interest rate thereof.

Applicant, on June 26, 1962, filed an amendment, pursuant to the requirements of the afore-mentioned Commission order, setting forth, among other things, that it proposes to accept, as providing the lowest annual cost of money to it, the bid of Halsey Stuart & Co. Inc. to purchase the proposed issuance of $5,000,000 principal amount of Bonds, for the price of 101.05% of principal amount, with an interest rate of 4⅞%.

The Commission finds:

(1) Applicant has satisfactorily complied with the requirements of paragraph (B) of the Commission's order issued June 14, 1962, in the above docket, and under the bid it proposes to accept for the Bonds, the price to be received by Applicant therefor and the interest rate thereof are reasonable.

(2) The proposed issuance and sale of Bonds, as hereinafter authorized, will be for a lawful object, within the corporate purposes of the Applicant and compatible with the public interest, which is appropriate for and consistent with the proper performance by the Applicant of service as a public utility and which will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purposes.

The Commission orders:

(A) The price to be received by Applicant for the proposed Bonds and the interest rate thereof under the bid referred to above are approved as reasonable.

(B) The proposed issuance and sale of Bonds referred to above, upon the terms and conditions and for the purposes specified in the application, as supplemented by the amendment referred to above, are hereby authorized subject only to the provisions of paragraphs (A), (C), (D), and (E) of the Commission's order issued June 14, 1962 in the above docket.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

EASTERN SHORE NATURAL GAS COMPANY, DOCKET NO. RP61-20

ORDER APPROVING OFFER OF SETTLEMENT

(Issued June 27, 1962)

On January 27, 1961, Eastern Shore Natural Gas Company (Eastern Shore) tendered for filing First Revised Sheet Nos. 5, 8, 11 and 18-A[1] to its FPC Gas Tariff, Original Volume No. 1.

The revised tariff sheets proposed a $7.164 demand charge and a 34¢ commodity charge in both the general service (G-1) rate schedule (Sheet No. 11) and the contract demand (CD-1) rate schedule (Sheets Nos. 5 and 8) and a 34¢ straight rate in the excess gas service (E-1) rate schedule (Sheet No. 18-A). The pre-existing rate levels were as follows: $5.75 demand charge and 32.5¢ commodity charge in both the general service and contract demand rate schedules and 32.5¢ straight rate in the excess gas service rate schedule. Eastern Shore requested that the revised sheets, estimated to increase jurisdic-

[1] A substitute First Revised Sheet No. 18-A was filed on February 6, 1961, to correct an error in the like-numbered sheet filed January 27, 1961.

tional revenues approximately $54,000, be permitted to become effective as of April 17, 1961.[2]

After a suspension by order issued February 24, 1961, in this proceeding, the aforementioned revised tariff sheets became effective as of April 17, 1961, subject to the terms and conditions set out in the order issued herein on May 12, 1961. By order issued May 15, 1961, Pennsylvania and Southern Gas Company (Pennsylvania and Southern) was permitted to intervene.

On April 3, 1962, Eastern Shore submitted a proposed offer of settlement of this proceeding to the parties. Conferences were held thereon and resulted in a "Stipulation of Settlement" which was placed on the record on May 17, 1962 (Tr. 44-46). As requested by Eastern Shore and concurred therein by Staff and Pennsylvania and Southern, the Presiding Examiner on May 22, 1962, certified the settlement proposal to the Commission for its consideration.

The settlement proposal provides (1) that for the period beginning April 17, 1961 and ending February 28, 1962, Eastern Shore shall refund to its customers the difference between the revenues actually collected and those which would have been collected pursuant to a $6.25 per Mcf per month demand charge and a 34¢ per Mcf commodity charge; (2) that for the period beginning March 1, 1962, Eastern Shore shall file revised tariff sheets providing for a $6.60 per Mcf per month demand charge and a 34¢ per Mcf commodity charge; (3) that Eastern Shore shall not file a general increase in rates prior to July 1, 1963, unless Transco increases the rate under its CD-3 rate schedule prior to that date; and (4) that Eastern Shore shall pass on to its customers the proportionate share of any further refunds Eastern Shore may receive from Transco applicable to the period covered by this proceeding.

The aforementioned proposed settlement is based upon a cost-of-service computed by the Staff. All parties to the proceeding have agreed to and signed the Stipulation of Settlement.

The Commission finds:

(1) The increased rates and charges contained in Eastern Shore's First Revised Sheet Nos. 5, 8 and 11 to its FPC Gas Tariff, Original Volume No. 1, have not been shown to be just and reasonable or otherwise lawful under the provisions of the Natural Gas Act, and should be disallowed as hereinafter provided and ordered.

(2) The settlement proposal referred to above is in the public interest and should be approved as hereinafter provided.

(3) Good cause exists for waiving the 30-day notice requirement provided in Section 154.22 of the Commission's Regulations under Natural Gas Act so that the revised tariff sheets under the proposed settlement agreement may become effective as of March 1, 1962, as hereinafter ordered.

The Commission orders:

(A) The increased rates and charges contained in Eastern Shore's First Revised Sheet Nos. 5, 8 and 11 to its FPC Gas Tariff Original Volume No. 1, are disallowed and denied.

(B) The rate for excess gas in Eastern Shore's First Revised Sheet No. 18-A to its FPC Gas Tariff, Original Volume No. 1, is hereby permitted to continue in effect without obligation to refund.

(C) Within 30 days from the date of this order, Eastern Shore shall file revised tariff sheets to its FPC Gas Tariff, Original Volume No. 1, in accordance

[2] The date to which Eastern Shore's sole supplier's (Transcontinental Gas Pipe Line Company's) proposed rate increase was suspended in Docket No. RP61-13. Transco's rate levels in that proceeding were subsequently determined by order issued February 2, 1962, 27 FPC 187.

with the provisions of the settlement agreement, subject to approval of the Commission.

(D) The 30-day notice provision in Section 154.22 of the Regulations under the Natural Gas Act is hereby waived and the revised tariff sheets filed pursuant to paragraph (C) are hereby permitted to become effective as of March 1, 1962, subject to the terms and conditions of this order and of the settlement proposal as set out in the record of this proceeding.

(E) Within 45 days from the date of this order, Eastern Shore shall refund the difference between the revenues actually collected from and after April 17, 1961, and those which would have been collected pursuant to the rates set out in the settlement agreement, plus interest at 7% per annum, from the date of payment of such excess until the date of refund.

(F) In the event Eastern Shore receives refunds from Transco for gas purchased by it from and after April 17, 1961, to and including the date of this order, Eastern Shore shall make further refunds, including interest, to its jurisdictional customers consistent with Article 4 (Tr. 45) of the settlement agreement.

(G) Within 15 days after refunding the excess revenues required by paragraphs (E) and (F), Eastern Shore shall report to the Commission, in writing and under oath, the amount of the refund made, showing separately the amount of principal and interest so paid, and shall serve a copy of such report upon each of its jurisdictional customers. Concurrently, therewith, Eastern Shore shall file with the Commission a release from each such jurisdictional customer, which shows the receipt of the aforementioned principal and interest.

(H) Upon full compliance by Eastern Shore with all the terms and conditions of this order, and acceptance by the Commission of the rate filing required by paragraph (C) this proceeding shall be considered terminated, subject only to the requirements of paragraph (F) above.

(I) This order is without prejudice to any findings or orders which have been or may hereafter be made by the Commission and is without prejudice to any claims or contentions which may be made by the Commission, the Commission Staff, Eastern Shore, or any other party affected by this order, in any proceeding now pending or hereafter instituted by or against Eastern Shore or any other company, person or party affected by this order.

Before Commissioners: Joseph C. Swidler, Chairman; Howard Morgan, L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

THE OHIO OIL COMPANY, DOCKET NO. RI60-92; THE OHIO OIL COMPANY, DOCKET NOS. G-12037, G-13465, G-13521, G-16672, G-16688, G-17275, G-17986, G-19763; THE OHIO OIL COMPANY (OPERATOR), *ET AL.*, DOCKET NO. G-20185; THE OHIO OIL COMPANY, DOCKET NOS. RI60-227, RI61-140, RI61-413, RI61-481, RI61-521, RI62-80

ORDER APPROVING GENERAL RATE SETTLEMENT PROPOSAL AND TERMINATING PROCEEDINGS

(Issued June 28, 1962)*

On May 7, 1962, The Ohio Oil Company (Ohio Oil) filed a petition requesting that the Commission issue an order approving a settlement proposal con-

*Clarifying order issued July 31, 1962, 28 FPC 254.

cerning the rates under 49 of its rate schedules[1] and the above related rate proceedings. The settlement proposal (attached hereto as an Appendix)* was served upon all parties to the above proceedings and was presented on May 7, 1962, to the Presiding Examiner in the rate hearings in Docket Nos. RI60–92, *et al.*[2] Philadelphia Electric Company, Public Service Electric and Gas Company, Long Island Lighting Company, and United Gas Improvement Company—active interveners in said hearings—made comments on the record at the session of May 7, 1962. On May 9, 1962, the Presiding Examiner certified to the Commission Ohio Oil's petition and settlement proposal and the transcript of the May 7 hearing. No one has objected to the settlement proposal.

The settlement proposal provides for (1) rates generally at or below applicable area ceilings, (2) an eighteen month moratorium on rate filings above ceiling,[3] and (3) waiver of the right to file for rate increases under favored-nation pricing provisions in two rate schedules. Ohio Oil submits the proposal on condition that the general rate investigation in Docket No. RI60–92 and the suspension proceedings listed above be terminated without requirement of refunds.

In support of the proposal, Ohio Oil states that the settlement disposes of most of its rate dockets without the necessity of prolonged and costly proceedings, that the moratorium and the waiver of certain favored-nation rights will provide an extended period of price stability and will reduce the number of Ohio Oil's rate filings and suspension proceedings, and that the subject rates will, with two exceptions, conform to established area rate patterns.

One settlement rate which exceeds the applicable ceiling is the increased rate of 16.25¢ plus 1.75¢ tax reimbursement under Rate Schedule No. 15 for a substantial sale of gas to United Gas Pipe Line Company from Duck Land Field, St. Martin and St. Mary Parishes, South Louisiana. The ceiling for increased rates in the area is 14.0¢ plus tax reimbursement (15.75¢ for this sale). In support of the proposed settlement rate, Ohio Oil states that the sale "involves the delivery of gathered, compressed and dehydrated gas under difficult and expensive circumstances . . . in a virtually impenetrable jungle-like wooded area, which is almost completely inundated at all times . . . The problems encountered in the operation of the field are thus more formidable and involve greater expense than is the case in other south Louisiana marshland fields." However, as we have recently noted, the in-line price in each area is determined at the customary point of delivery in that area. *Standard Oil Company of California, et al.*, Docket Nos. CI60–333, *et al.* (Opinion No. 359), issued June 11, 1962, 27 FPC 1153 at 1159. Ohio Oil's incurrence of additional expense does not show service beyond the customary point of delivery in the area.

But we find the proposed settlement rate under Rate Schedule No. 15 acceptable for other reasons. The basic contract, dated August 1, 1952, pro-

[1] Most of Ohio Oil's other rate schedules, not subject to the settlement proposal, will be subject to determinations in Docket Nos. AR61–1, *et al.*, or are rate schedules recently succeeded to by Ohio Oil from Plymouth Oil Company.

* Omitted in printing.

[2] Hearings commenced on September 13, 1960, in the general rate investigation in Docket No. RI60–92 and the consolidated suspension proceedings in Docket Nos. G–12037 through G–20185 listed above. Settlement negotiations commenced on March 5, 1962, upon the suggestion of the Presiding Examiner and were culminated by the presentation of the settlement proposal at the final hearing session on May 7, 1962. No briefs have been filed in the proceedings, nor has an Examiner's decision been issued therein.

[3] Ohio Oil reserves the right to file during the moratorium for increases up to applicable increased rate ceilings except that under Rate Schedule No. 10 Ohio Oil may file for increases only up to the 14.0¢ ceiling might otherwise be applicable.

vided for an initial price of 11.5¢ plus tax reimbursement, with subsequent periodic escalations. No sales were made under the contract until after the pricing provisions were renegotiated. As a result of renegotiation provision was made for a fixed escalation to 20.2¢ per Mcf to become effective soon after the commencement of deliveries. Under these unusual circumstances, the increased price may here be considered in the nature of an initial price and is, at the proposed settlement level, compatible with the initial rate ceiling. We shall therefore approve the proposed settlement rate.

The other settlement rate which exceeds the applicable ceiling is the increased rate of 17.0¢ including tax reimbursement under Rate Schedule No. 56 for a small sale of gas from Barby Ranch Unit (Tract 12), Panhandle Area, Oklahoma. The ceiling for increased rates in the area is 11.0¢ including tax reimbursement. In support of the proposed settlement rate Ohio Oil states as follows: Ohio Oil's lease is on state property and was, according to state rules, subject to cancellation unless a prompt sale of gas was negotiated. Ohio Oil therefore made a one-year temporary sale at 15.0¢ per Mcf while other leaseholders in the unit—whose leases were not subject to short cancellation by their private landowners—were still trying to negotiate sales of gas at 17.0¢. When the others finally made their sale Ohio Oil adopted the permanent gas sales contract executed by the operator of the unit, thereby obtaining an increase in price from 15.0¢ under the temporary contract to 17.0¢ under the adopted superseding permanent contract. Although the 17.0¢ rate was suspended and later made effective subject to refund in Docket No. RI61–413, under the circumstances it may be deemed in the nature of an initial rate and is, judged accordingly, acceptable as being in line with the applicable 17.0¢ initial ceiling.

As we recently stated, the Commission approves of and wants to encourage settlements which dispose of most of a producer's pending rate problems, which do so in accord with our area rate ceilings,[4] which provide for a reasonable moratorium on increased rate filings, which require refunds where appropriate, which lend certainly to the purchased gas costs of buyers, and which free the producer's revenues from contingencies that inhibit exploratory and developmental activities. *Tidewater Oil Company, et al.*, Docket Nos. G–13310, *et al.*, Order Conditionally Approving General Rate Settlement, issued June 15, 1962, *supra*, P. 1267. We note that no refunds will be made under Ohio Oil's Settlement. However, as stated in its petition, all the cost of service analyses presented in Docket Nos. RI60–92, *et al.*, indicated that Ohio Oil's test year jurisdictional revenues did not exceed jurisdictional costs, and this situation probably continued in subsequent years due to declining volumes. Ohio Oil may therefore be relieved of any obligation to make refunds in the subject proceedings, as provided in the settlement proposal. Otherwise the settlement proposal provides the substantial benefits noted above and is in the public interest and should be approved.

Our approval of the settlement proposal should not be construed as constituting approval of any future rate increases that may be filed under the subject rate schedules and is without prejudice to any findings or orders of the Commission in any further proceedings, including area rate proceedings, involving Ohio Oil's rates and rate schedules.

The Commission finds:

(1) The settlement of the proceedings, listed below, on the basis of the settlement proposal submitted by Ohio Oil is in the public interest in carry-

[4] *Statement of General Policy No. 61–1*, 24 FPC 818, as amended.

ing out the provisions of the Natural Gas Act and should be approved and made effective.

(2) Rates under the rate schedules subject to the settlement should be disallowed to the extent they exceed the settlement rates.

The Commission orders:

(A) The settlement of the proceedings in Docket Nos. RI60-92, G-12037, G-13465, G-13521, G-16671, G-16688, G-17275, G-17986, G-19763, G-20185, RI60-227, RI61-140, RI61-413, RI61-481, RI61-521, and RI62-80 on the basis of the settlement proposal attached hereto as the Appendix is approved and made effective.

(B) Rates under the rate schedules subject to the settlement are hereby disallowed to the extent they exceed the settlement rates listed in Column 5 of Exhibit A hereto.

(C) Within 45 days after the date of this order Ohio Oil shall make such filings under its rate schedules as are required to make effective the terms of the settlement proposal.

(D) Upon full compliance by Ohio with all the terms of this order and of the settlement proposal, Ohio Oil shall be relieved of any refund obligations in the proceedings listed in paragraph (A) above and said proceedings shall terminate.

(E) This order is without prejudice to any findings or orders which have been or may be made hereafter by the Commission, and is without prejudice to claims or contentions which may be made by the Commission, Ohio Oil, the Commission staff, or any affected party herein, in any proceedings now pending or hereafter instituted by or against Ohio Oil or any other companies, persons, or parties affected by this order.

EXHIBIT A

THE OHIO OIL COMPANY

Proposed Rates

(1) Purchaser	(2) Field	(3) Rate Schedule No.	(4) Present price [1]	(5) Proposed settlement price [1]	(6) Section 4 (e) Docket No.
Texas Railroad Commission District No. 3:					
Tennessee Gas Trans. Co.	Nelsonville	8	[2] 15.95016	[2] 14.6	G-17275.
Transcontinental G.P.L. Co.	Markham	10	[4] 9.542074	[4] 9.542074	
Tennessee Gas Trans. Co.	North Garwood	11	[2] 16.16947	[2] 14.6	G-17275.
United G.P.L. Co.	Phoenix Lake	[6] 14	15.5	15.5	
United G.P.L. Co.	Phoenix Lake	[6] 32	15.8584	15.8584	
Texas Railroad Commission District No. 4:					
Transcontinental G.P.L. Co.	LaGloria	12	[7] 8.890883	[7] 8.890883	
Natural G.P.L. Co. of America.	LaGloria	13	9.998857	9.998857	
Coastal Transmission Corp.	Half Moon Reef	46	17.0	17.0	
Texas Railroad Commission District No. 6:					
Arkansas Louisiana Gas Co.	Jefferson Rodessa	21	[8] 7.54244	[8] 7.54244	
Arkansas Louisiana Gas Co.	Moseley No. 1	37	3.00	3.00	

[1] Louisiana, Mississippi, Colorado, New Mexico, Utah and Wyoming prices at 15.025 psia; all other prices at 14.65 psia. Unless otherwise noted, all prices are base prices, plus tax reimbursement, if any.
[2] After deduction for dehydration.
[3] "Favored nations" provision eliminated; settlement rate is inclusive of all charges, including dehydration.
[4] Contract price and pressure base: 10.88102¢ at 16.7 psia; price varies slightly from time to time with changes in tax exempt royalty production.
[5] Includes dehydration charge.
[6] Covers gas produced in Louisiana (but delivered in Texas); rate under R.S. 14 approved by Order issued Sept. 19, 1961, terminating proceeding in Docket No. RI61-421.
[7] Contract Price and pressure base: 10.135¢ at 16.7 psia.
[8] Before deduction for compression.

THE OHIO OIL COMPANY—Continued

(1) Purchaser	(2) Field	(3) Rate Schedule No.	(4) Present price [1]	(5) Proposed settlement price [1]	(6) Section 4 (e) Docket No.
Texas Railroad Commission District No. 10:					
Phillips Petroleum Co.	East Sweet	9	8.0	8.0	
Northern Louisiana:					
United G.P.L. Co.	Cotton Valley	17	11.76876	11.76876	
Louisiana Nevada Transit Co.	Cotton Valley	[9] 18			
Arkansas Louisiana Gas Co.	East Haynesville	20	13.47833	13.47833	
Arkansas Louisiana Gas Co.	Ada	26	12.26	12.26	
Texas Eastern Trans. Corp.	Logansport	28	16.4161	15.75	G-13521, G-16672, G-19763, RI61-140, RI62-80.
Texas Eastern Trans. Corp.	Logansport	29	16.4161	15.75	G-13521, G-16672, G-19763, RI61-140, RI62-80.
United G.P.L. Co.	Ada	38	[10] 18.25	[10] 18.25	
United G.P.L. Co.	Cotton Valley	52	11.26876	11.26876	
United G.P.L. Co.	Cotton Valley	53	11.26876	11.26876	
Texas Gas Trans. Co.	Calhoun	60	18.75	18.75	
Southern Louisiana:					
United G.P.L. Co.	Duck Lake	15	22.95	18.0	G-12037, G-13465.
United G.P.L. Co.	Theall	36	20.25	20.0	
Mississippi:					
United G.P.L. Co.	Maxie-Pistol Ridge	16	23.0	20.126	G-20185.
Oklahoma:					
Panhandle Area					
Colorado Interstate Gas Co.	Laverne	30	15.0	15.0	
Colorado Interstate Gas Co.	Mocane	31	15.0	15.0	
Natural G.P.L. Co. of America.	Camrick S.E.	35	17.0	16.4	G-17986, RI60-227 RI61-481.
Northern Nat. Gas Co.	Barby Ranch Unit (Tract 12).	[11] 40			
Northern Nat. Gas Co.	Rosston Area	41	15.0	15.0	
Panhandle Eastern P.L. Co.	Western Mocane	43	16.0	16.0	
Natural G.P.L. Co.	Southeast Boyd	48	16.0	16.0	
Panhandle Eastern P.L. Co.	Barby "C" and Hamilton Units.	50	17.0	17.0	
Northern Nat. Gas Co.	Barby Ranch Unit (Tract 12).	56	17.0	17.0	RI61-413.
Michigan Wisconsin P.L. Co.	Laverne	62	17.0	17.0	
Carter Knox					
Lone Star Gas Co.	Knox	47	16.8	16.8	
Other					
Cities Service Gas Co.	Grant County	58	[12] 12.0	[12] 12.0	
Kansas:					
Michigan Wisconsin P.L.	Nichols	33	15.0	15.0	
Nothern Nat. Gas Co. Co.	Riffel Unit	45	13.0	12.0	RI61-521.
Panhandle Eastern P.L. Co.	Southeast Wil	49	15.0	15.0	
Cities Service Gas Co.	Rhodes	57	12.0	12.0	
Cities Service Gas Co.	Hardtner	59	12.0	12.0	
Panhandle Eastern P.L. Co.	Hugoton	61	11.0	11.0	
Colorado:					
Kansas Nebraska Nat. Gas Co.	Padroni	19	[13] 13.74238	[14] 12.82622	G-16688.
Kansas Nebraska Nat. Gas Co.	Rush Creek	23	[10] 11.91006	[15] 11.91006	

[9] Superseded by Cotton Valley Operators Committee FPC Gas Rate Schedule No. 1.
[10] As established by Commission's Order of March 21, 1962, in *The Ohio Oil Company (Operator) et al.*, Docket Nos. G-15385, et al.
[11] Superseded by R.S. 56.
[12] Before deduction for dehydration.
[13] Contract price and pressure base: 15.0¢ at 16.4 psia.
[14] 14.0¢ at 16.4 psia.
[15] Contract price and pressure base: 13.0¢ at 16.4 psia.

THE OHIO OIL COMPANY—Continued

(1) Purchaser	(2) Field	(3) Rate Schedule No.	(4) Present price [1]	(5) Proposed settlement price [1]	(6) Section 4 (e) Docket No.
New Mexico:					
San Juan Basin					
El Paso Nat. Gas Co.	LaPlata	24	12.0	12.0	
El Paso Nat. Gas Co.	Jicarilla	25	11.0	11.0	
El Paso Nat. Gas Co.	Kutz Canyon	55	12.0	12.0	
Utah:					
El Paso Nat. Gas Co.	Aneth	44	17.7	17.7	
Wyoming:					
Montana-Dakota Util. Co.	Little Buffalo Basin	[16] 1			
Montana-Dakota Util. Co.	Garland	2	8.5	8.5	
Montana-Dakota Util. Co.	Elk Basin	[17] 3			
Montana-Dakota Util. Co.	Elk Basin	34	8.0	8.0	
West Virginia:					
Cumberland & Allegheny Gas Co.	Canaan Valley	22	[18] 19.119086	[18] 19.119086	

[16] Abandoned pursuant to Commission's Order of Jan. 3, 1961, in Docket No. G-18803. (See *Pan American Petroleum Corporation*, Docket No. G-18704).
[17] Superseded by R.S. 34.
[18] Contract price and pressure base: 20.0¢ at 15.325 psia.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

AMERICAN LOUISIANA PIPE LINE COMPANY, DOCKET NO. CP62-94; TENSAS GAS GATHERING CORPORATION, DOCKET NO. CP62-127; TEXAS SAN JUAN OIL CORPORATION, DOCKET NO. CI62-382

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 29, 1962)

On October 12, 1961, as supplemented on March 7, 1962, American Louisiana Pipe Line Company (American Louisiana) filed in Docket No. CP62-94 an application pursuant to Section 7(c) of the National Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of approximately 27.1 miles of gathering lines of various diameters, a purchase meter station, and 660 horsepower of field compression facilities to receive natural gas from the Holly Ridge Area of Louisiana and Mississippi, all as more fully set forth in the application as supplemented.

American Louisiana estimates the total cost of the proposed facilities to be $1,125,000, which will be financed from funds on hand.

The proposed facilities will enable American Louisiana to purchase gas from reserves in Tensas, Franklin, Catahoula, and Concordia Parishes, Louisiana, and in Jefferson, Claiborne, and Adams Counties, Mississippi, committed to it under the provisions of a gas purchase contract with Phillips Petroleum Company and G. H. Jett, subsequently assigned to Texas San Juan Oil Corporation (Texas San Juan). The initial rate to be paid under the contract is 17.0 cents per Mcf plus applicable tax reimbursement.

The gas to be purchased will be gathered through the proposed gathering facilities by Texas San Juan and delivered to American Louisiana at a point in Tensas Parish, Louisiana, after processing in Texas San Juan's Locust Ridge Plant. The gas will be transported by Tensas Gas Gathering Corporation

(Tensas) from the Locust Ridge Plant to American Louisiana's 8⅝-inch supply lateral previously authorized in Docket No. CP61–24.

The purchase of gas from the Holly Ridge Area will augment American Louisiana's system gas supply. No new sales are proposed under the subject application, and no increase in the delivery capacity of Applicant's certificated pipeline system is necessary to effectuate the proposal in the subject application.

On October 13, 1961, as supplemented on March 7, 1962, Texas San Juan Oil Corporation filed in Docket No. CI62–382 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the sale of natural gas to American Louisiana after processing in the Locust Ridge Plant, as hereinbefore described, all as more fully described in the application as supplemented.

On November 21, 1961, as supplemented on March 7, 1962, Tensas Gas Gathering Corporation filed in Docket No. CP62–127 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the transportation of natural gas from the outlet of the Locust Ridge Plant to a connection with American Louisiana's 8⅝-inch lateral in Tensas Parish, Louisiana, through Tensas' existing 8-mile, 8-inch pipeline in Tensas Parish, as hereinbefore described, all as more fully described in the application as supplemented.

On April 13, 1962, the Applicants herein were granted temporary authorization to construct and operate the facilities and to render the service proposed.

Pursuant to due notice, a public hearing was held in Washington, D. C. on June 21, 1962, respecting the matters involved in and the issues presented by the applications herein. No protests to the granting of the applications or petitions to intervene have been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, American Louisiana Pipe Line Company, a Delaware corporation having its principal place of business in Detroit, Michigan, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of October 1, 1954, in Docket No. G–2306, *et al.* (13 FPC 380).

(2) Applicant, Tensas Gas Gathering Corporation, a Louisiana corporation having its principal place of business in Shreveport, Louisiana, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of March 31, 1958, in Docket No. G–13588 (19 FPC 411).

(3) Applicant, Texas San Juan Oil Corporation, a Delaware corporation having its principal place of business in Dallas, Texas, is a "natural-gas company" within the meaning of the Natural Gas Act and is engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption.

(4) The sale of natural gas hereinbefore described, as more fully described in the application, as supplemented, in Docket No. CI62–382, will be made in interstate commerce subject to the jurisdiction of the Commission, and such sale, together with the construction and operation of any facilities subject to the jurisdiction of the Commission necessary therefor, is subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(5) The sale of natural gas by Applicant in Docket No. CI62–382, together with the construction and operation of any facilities subject to the jurisdiction

of the Commission necessary therefor, is required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(6) The facilities proposed to be constructed and operated in Docket No. CP62–94 and the transportation of natural gas proposed in Docket No. CP62–127, as hereinbefore described, all as more fully described in the applications in said dockets, are subject to the jurisdiction of the Commission, and the construction and operation of facilities and the transportation of natural gas by the respective Applicants as aforesaid are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(7) Applicants are able and willing properly to do the acts and to perform the services proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(8) The construction and operation of facilities and the transportation of natural gas described in paragraph (6) above are required by the public convenience and necessity and certificates therefor should be issued as hereinafter ordered and conditioned.

(9) Public convenience and necessity require that the certificates issued hereinafter in Docket Nos. CP62–94 and CP62–127 and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (b), (c) (3), and (e) of Section 157.20 of such Regulations, and further, the certificate issued hereinafter and Applicant's compliance with paragraph (c) (4) of Section 157.20 of such Regulations.

the rights granted thereunder in Docket No. CP62–94 should be conditioned upon

(10) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30(c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) Certificates of public convenience and necessity be and the same are hereby issued authorizing the Applicants in Docket Nos. CP62–94 and CP62–127 to construct and operate facilities and to transport natural gas in interstate commerce, and the Applicant in Docket No. CI62–382 to sell natural gas in interstate commerce for resale, as applied for in the respective applications, as hereinbefore described and as more fully described in said applications, upon the terms and conditions of this order.

(B) The certificates issued by paragraph (A) above and the rights granted thereunder are conditioned upon Applicants' compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraph (e) of Section 157.20 of such Regulations, and further the certificates issued by paragraph (A) above in Docket Nos. CP62–94 and CP62–127 and the rights granted thereunder are conditioned upon Applicants' compliance with paragraphs (b) and (c)(3) of Section 157.20 or such Regulations, and the certificate issued in Docket No. CP62–94 and the rights granted thereunder is conditioned upon Applicant's compliance with paragraph (c)(4) of Section 157.20 of such Regulations.

(C) The facilities authorized in Docket No. CP62–94 shall be constructed and placed in actual operation, and the transportation of natural gas authorized in Docket No. CP62–127 shall commence, as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act, within 6 months from the date on which this order issues.

(D) The grant of the certificate issued by paragraph (A) above in Docket No. CI62-382 shall not be construed as waiver of the requirements of Section 4 of the Natural Gas Act or of Part 154 or Part 157 of the Commission's Regulations thereunder, and is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Applicant. Further, our action in this proceeding shall not foreclose nor prejudice any future proceedings or objections relating to the operation of any price or related provisions in the gas purchase contracts herein involved. Nor shall the grant of the certificate aforesaid for service to the particular customer involved imply approval of all the terms of the contract, particularly as to the cessation of service upon termination of said contract, as provided by Section 7(b) of the Natural Gas Act. Nor shall the grant of the certificate aforesaid be construed to preclude the imposition of any sanctions pursuant to the provisions of the Natural Gas Act for the unauthorized commencement of any sales of natural gas subject to said certificate.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

EQUITABLE GAS COMPANY, DOCKET NO. CP62-186

FINDINGS AND ORDER ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

(Issued June 29, 1962)

On February 12, 1962, as supplemented on March 12, 1962, Equitable Gas Company (Applicant) filed in Docket No. CP62-186 an application pursuant to Section 7(c) of the Natural Gas Act for a certificate of public convenience and necessity authorizing the construction and operation of certain underground gas storage facilities for the operation of Applicant's proposed Mobley Storage Field, located in Wetzel County, West Virginia, all as more fully set forth in the application as supplemented.

The operation of the proposed Mobley Field will provide additional storage capacity for Applicant of approximately 2,500,000 Mcf, and when in full operation the field is expected to permit the withdrawal of approximately 1,500,000 Mcf per heating season. The activation of the Mobley Field and the deliverability available from it will assist Applicant in meeting its increasing requirements, especially its customers' space heating demands during peak periods.

In addition to reconditioning a total of 20 wells for storage, Applicant proposes to construct approximately 9 miles of 12-inch pipeline extending from a point of connection located at its Logansport Storage Pool to a point of connection with its present transmission system, and approximately 3.2 miles of 12-inch pipeline extending from its Logansport Compressor Station to the Mobley Storage Field, together with approximately 5.8 miles of 6-inch and 8-inch well-connecting lines, metering equipment, and yard piping at the Logansport Station.

Applicant plans to develop the Mobley Field as soon as possible so that a portion of the facilities will be in operation during the 1962 injection cycle and to complete the entire project commencing with the 1964 injection season.

The estimated total cost of the proposed facilities is $1,929,240, which will be financed from general funds available to Applicant.

Pursuant to due notice, a public hearing was held in Washington, D. C., on June 12, 1962, respecting the matters involved in and the issues presented by the application herein. No protest to the granting of the application or petition to intervene has been received. Staff counsel moved orally at the hearing that the intermediate decision procedure be omitted and that the Commission render a decision herein pursuant to Section 1.30 (c) (1) of its Rules of Practice and Procedure.

The Commission finds:

(1) Applicant, a Pennsylvania corporation having its principal place of business in Pittsburgh, Pennsylvania, is a "natural-gas company" within the meaning of the Natural Gas Act as heretofore found by the Commission in its order of May 9, 1944, in Docket No. G–275 (4 FPC 588).

(2) The facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, will be used in the transportation and sale of natural gas in interstate commerce subject to the jurisdiction of the Commission, and the construction and operation thereof by Applicant are subject to the requirements of Subsections (c) and (e) of Section 7 of the Natural Gas Act.

(3) Applicant is able and willing properly to do the acts and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules, and regulations of the Commission thereunder.

(4) The proposed construction and operation of facilities are required by the public convenience and necessity, and a certificate therefor should be issued as hereinafter ordered and conditioned.

(5) Public convenience and necessity require that the certificate issued hereinafter and the rights granted thereunder be conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations.

(6) The time within which the facilities should be completed and placed in actual operation should be fixed at 24 months from the date on which this order issues.

(7) The maximum average storage pressure of 800 psig should not be exceeded without further authorization by the Commission.

(8) Applicant should submit semi-annual reports as hereinafter ordered containing information on the characteristics and capabilities of the storage field.

(9) A request during the public hearing by staff counsel for omission of the intermediate decision procedure herein was unopposed by any party of record and, not having been denied by the Commission, is granted pursuant to Section 1.30 (c) (1) of the Commission's Rules of Practice and Procedure.

The Commission orders:

(A) A certificate of public convenience and necessity be and the same is hereby issued authorizing Applicant, Equitable Gas Company, to construct and operate the facilities hereinbefore described, as more fully described in the application, as supplemented, in this proceeding, upon the terms and conditions of this order.

(B) The certificate issued by paragraph (A) above and the rights granted thereunder is conditioned upon Applicant's compliance with all applicable Commission Regulations under the Natural Gas Act and particularly the general terms and conditions set forth in paragraphs (a), (b), (c) (3), (c) (4), and (e) of Section 157.20 of such Regulations.

(C) The time within which the facilities shall be completed and placed in actual operation as provided by paragraph (b) of Section 157.20 of the Commission's Regulations under the Natural Gas Act is hereby fixed at 24 months from the date on which this order issues.

(D) The maximum average storage pressure of 800 psig shall not be exceeded without further authorization by the Commission.

(E) With respect to the Mobley Field, Applicant shall submit semi-annual reports, coinciding with the termination of the input and withdrawal cycles, showing the total volumes of natural gas injected and withdrawn from the field, the shut-in pressure of each well, the average of such pressures, and the corresponding volume of natural gas in the storage reservoir, together with a statement by months of the total volumes of gas injected or withdrawn, the maximum day injection or withdrawal rate experienced, and the average working pressure on such days at a central measuring point at which the total volume is measured. The report shall include additional statements or information that will indicate the pattern of use during the withdrawal cycle. There shall be included with each report a map showing the shut-in pressures in all storage wells and similar pressures in all wells in the area immediately adjacent to the storage field. Reports shall be filed until Applicant has completed two injection and withdrawal cycles when the stabilized shut-in storage pressure after the injection cycle has reached or has closely approximated a maximum storage pressure of 800 psig.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

PANHANDLE EASTERN PIPE LINE COMPANY, DOCKET NO. CP60-103; SHELL OIL COMPANY, DOCKET NO. CI60-660; PIONEER PRODUCTION CORPORATION, DOCKET NO. CI60-689; CALVERT PETROLEUM COMPANY, CI60-691; ASHLAND OIL & REFINING COMPANY, CI60-738; UNION OIL COMPANY OF CALIFORNIA, DOCKET NO. CI60-802; KING-STEVENSON OIL COMPANY, INC., DOCKET NO. CI60-813

ORDER PERMITTING LATE FILING AND ISSUING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY NUNC PRO TUNC

(Issued June 29, 1962)

By ordering paragraph (B) of our Opinion No. 350 issued on January 15, 1962, 27 FPC 35, in the above-captioned consolidated proceeding[1] we provided:

(B) Within 30 days from the date of the issuance of this order, Pioneer Production Corporation, Ashland Oil & Refining Company and Union Oil Company of California shall have the option to rescind the cancellation of their contracts with Panhandle and the notices of withdrawal from this proceeding, and to notify the Commission of the resubmittal of their applications on the same terms and conditions originally applied for by them in this proceeding. In the event such resubmission is made, the applications shall be reinstated and certificates shall thereupon be issued, *nunc pro tunc*, to the producer applicants making such resubmission, authorizing the sale of natural gas in interstate commerce as proposed; subject, however, to the same conditions as hereinafter set forth with respect to the other independent producers.

[1] An order clarifying Opinion No. 350 was issued on February 5, 1962, 27 FPC 52.

Pursuant to the aforecited provision, but however not within the time designated, Ashland Oil & Refining Company (Ashland) on February 26, 1962, filed for reinstatement and acceptance, its previously withdrawn application in Docket No. CI60–738 as now amended along with its proposed amended rate schedule. Ashland's application, as originally filed, proposed the sale of gas to Panhandle at an initial price of 17 cents per Mcf to be produced from acreage in the Oklahoma Counties of Woodward, Woods, Major and Dewey. Under the amended application all of the Woodward County acreage has been deleted as well as certain specified acreage in Woods County. In lieu thereof, Ashland has substituted some additional acreage in Woods, Major and Dewey Counties. By its amended rate schedule, designated Ashland Oil & Refining Company FPC Gas Rate Schedule No. 78 along with Supplements Nos. 1 and 2 thereof, Ashland has agreed to an initial price of 15 cents per Mcf at 14.65 psia plus Btu adjustment.

Although Ashland's filing was not made within the time designated and the resubmitted proposal does not encompass "the same terms and conditions originally applied for", *i.e.*, there has been a partial substitution of acreage, neither fact is of sufficient significance so as to warrant rejection of the amended application. In essence, it conforms in full to our ordering paragraph (B) aforecited.

The Commission orders:

(A) Ashland Oil & Refining Company is hereby granted permission to make a filing in accord with Ordering Paragraph (B) of Commission Opinion No. 350 beyond the 30-day period designated therein.

(B) Ashland's amended application filed on February 5, 1962, is hereby accepted for filing. The rate schedule accompanying said amended application is also accepted for filing effective as of the date of initial delivery.

(C) A certificate of public convenience and necessity is hereby issued to Ashland for the sale of gas to Panhandle Eastern Pipe Line Company in accord with the amended application and the rate schedule previously referred to, such certification being subject to all the conditions set forth in our Opinion No. 350 and related clarifying order of February 5, 1962.

(D) The certificate herein issued to Ashland shall be accepted in writing and under oath within 30 days from the date of the issuance of this order.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Conner, Jr., Charles R. Ross and Harold C. Woodward.

THE SUBURBAN FUEL GAS, INC., DOCKET NO. CP62–224

FINDINGS AND ORDER DIRECTING PHYSICAL CONNECTION OF FACILITIES AND SALE OF NATURAL GAS

(Issued June 29, 1962)

On March 28, 1962, as supplemented on April 30, 1962, The Suburban Fuel Gas, Inc. (Applicant) filed in Docket No. CP62–224 an application for an order pursuant to Section 7 (a) of the Natural Gas Act directing The Ohio Fuel Gas Company (Ohio Fuel) to establish physical connection of its transmission facilities with the proposed facilities of and to sell natural gas to Applicant for resale in the villages of Tontogany and Grand Rapids, Wood County, Ohio, and McClure, Henry County, Ohio, and in the vicinity of said villages.

The villages will construct and own their distribution systems as well as 13.7 miles of 6-inch and 6 miles of 4-inch transmission pipeline and related facilities. Applicant, under lease agreements with the villages, will operate all the proposed facilities.

The physical connection of Ohio Fuel's transmission facilities with the facilities of Applicant will be made in Center Township, Wood County, Ohio.

The estimated peak day requirements for the villages total 912 Mcf of natural gas in the third year of service. Total annual requirements are estimated to be 188,000 Mcf in the third year of service.

The total estimated cost of transmission and distribution facilities for the projects aggregate $627,000, which cost will be financed by the villages through local revenue bond issues.

On April 26, 1962, Ohio Fuel filed an answer to the subject application stating that it had no objection to a Commission order directing the sale.

Due notice of the filing of the application and opportunity for hearing thereon has been given by publication in the Federal Register on May 24, 1962 (27 FR 4897). No protest or petition to intervene has been filed in this proceeding.

The Commission finds:

(1) The Ohio Fuel Gas Company, an Ohio corporation having its principal place of business in Columbus, Ohio, is a "natural-gas company" within the meaning of the Natural Gas Act, as heretofore found by the Commission in its order of August 21, 1945, in Docket No. G–371 (4 FPC 1033).

(2) Applicant, The Suburban Fuel Gas, Inc., is an Ohio corporation having its principal place of business in Cygnet, Ohio, and is duly authorized to engage in the business of distributing and selling natural gas within the State of Ohio.

(3) It is necessary and desirable in the public interest that Ohio Fuel be directed to establish physical connection of its natural gas transportation system with the proposed facilities to be operated by Applicant and to sell and deliver natural gas to Applicant, as set forth in the application, as supplemented, and as hereinafter ordered and conditioned. In this connection, Ohio Fuel shall offer Applicant not less than the latter's third year peak day requirement of 912 Mcf.

(4) Applicant should be prepared to receive natural gas from Ohio Fuel within one year of the date of issuance of this order.

(5) The requirement that Ohio Fuel serve Applicant, as proposed, will not place any undue burden upon Ohio Fuel nor impair its ability to render adequate service to its existing customers.

The Commission orders:

(A) The Ohio Fuel Gas Company be and it is hereby directed to establish physical connection of its natural gas transportation system with the proposed facilities to be operated by Applicant and to sell and deliver natural gas to Applicant, all as hereinbefore described and as set forth in the application, as supplemented. Ohio Fuel shall offer Applicant not less than the latter's third year peak day requirement of 912 Mcf.

(B) Applicant shall be prepared to receive natural gas from Ohio Fuel within one year from the date of issuance of this order.

(C) Ohio Fuel shall report to the Commission in writing and under oath the date of commencement of service to Applicant.

Before Commissioners: Joseph C. Swidler, Chairman; L. J. O'Connor, Jr., Charles R. Ross and Harold C. Woodward.

UNITED GAS PIPE LINE COMPANY, DOCKET NO. G–233; NATURAL GAS PIPELINE COMPANY OF AMERICA, DOCKET NO. G–235A; ARKANSAS LOUISIANA GAS COMPANY, DOCKET NO. G–253; MONTANA-DAKOTA UTILITIES COMPANY, DOCKET NO. G–584; NORTHERN NATURAL GAS COMPANY, DOCKET NO. G–643; COLORADO-WYOMING GAS COMPANY, DOCKET NO. G–738; NORTH CENTRAL GAS COMPANY, DOCKET NO. G–758; NORTHERN UTILITIES COMPANY, DOCKET NO. G–759; WASHINGTON GAS LIGHT COMPANY, DOCKET NO. CP62–205.

ORDER DISMISSING REQUESTS MADE PURSUANT TO SECTION 7(F) OF THE ACT AND FIXING DATE OF HEARING

(Issued June 29, 1962)

All of the above-captioned applicants have filed applications requesting that the Commission make a determination pursuant to Section 7(f) of the Natural Gas Act prescribing service areas all as more fully set forth in their applications which are on file with the Commission and open to public inspection.

Applications in the above-captioned dockets were filed on the dates indicated below:

Docket No.	Applicant	Date filed
G–233	United Gas Pipe Line Company	2–11–42
G–235A	Natural Gas Pipeline Company of America	2–23–42
G–253	Arkansas Louisiana Gas Company	4–14–42
G–584	Montana-Dakota Utilities Company	10–7–42
G–643	Northern Natural Gas Company	6–18–45
G–738	Colorado-Wyoming Gas Company	6–17–46
G–758	North Central Gas Company	7–22–46
G–759	Northern Utilities Company	7–22–46
CP62–205	Washington Gas Light Company	2–28–62

Washington Gas Light Company (Washington) is the only applicant who has, within a decade, submitted a filing for a determination under Section 7(f) of the Act. Washington seeks a determination of a service area by the Commission under Section 7(f) of the Act in order to enable it without further authorization of this Commission to enlarge or extend its facilities to meet increased customer requirements within such service area.

The territory which applicant requests the Commission to include in the determination of Applicant's requested service area consists of the following:

The District of Columbia; Montgomery and Prince George's Counties in Maryland; Arlington, Fairfax, Loudoun, and Prince William Counties in Virginia; and all cities now or hereafter existing in Maryland or Virginia within the geographic area bounded by the outer boundaries of the combined area of said counties exclusive, however, of the following areas:

Exclusion 1. The area in Prince George's County, Maryland, known as Laurel Election District Number 10, of Prince George's County, and described more fully in the application.

Exclusion 2. The area in Prince William County, Virginia, known as Dumfries and vicinity, and Quantico Marine Base and territory adjacent thereto along the southern boundary of Prince William County and described more fully in the application.

Washington makes no sales for resale. All the natural gas received by Washington is received within its service area and is ultimately consumed within such area. Washington's rates, service and facilities in the District of Columbia are subject to regulation by the Public Utilities Commission of the District of Columbia; those in Maryland by the Public Service Commission of Maryland; and those in Virginia by the State Corporation Commission of Virginia.

The population of the metropolitan area is continuing to expand and Washington anticipates the continued expansion of business in the Requested Service Area, especially in Maryland and Virginia. In order to meet the requirements of an expanding population it will be necessary for Washington to constantly extend new mains from its present distribution system.

Any extension of service by Washington will be pursuant to and in accordance with the regulations and orders of the respective regulatory commissions of the two states and the District of Columbia. A determination by this Commission puruant to Section 7(f) relative to the service area requested by Washington, will enable that company to extend its presently existing facilities without requiring such extensions to be the subject of duplicative regulation.

An analysis of the applications filed by the other above-captioned applicants makes it manifest that they are not similar to Washington which is primarily a local distributor having no rates subject to federal regulation.

It is also apparent from the language of Section 7(f) of the Act that even after a formal hearing, it is within the discretion of the Commission as to whether or not it should define a service area.

The provisions of Section 7(f) of the Act are as follows:

(f) The Commission, after a hearing had upon its own motion or upon application, may determine the service area to which each authorization under this Section is to be limited. Within such service area as determined by the Commission a natural-gas company may enlarge or extend its facilities for the purpose of supplying increased market demands in such service area without further authorization.

It seems manifest that the restricted application of Section 7(f) of the Act to those facts underlying the Washington filing enables that Section to contribute to the over-all regulatory scheme envisaged by the Natural Gas Act. It is equally apparent that if the Commission in its discretion were to permit other types of applicants, particularly interstate pipelines which perform essentially a transmission service, to invoke the provisions of Section 7(f) of the Act that interminable disputes and long drawn-out hearings of dubious benefit would necessarily ensue.

The Commission finds:

(1) That each of the above-captioned applicants is a natural gas company subject to the provisions of the Natural Gas Act.

(2) That Washington is primarily a distribution company and the extension of its facilities is subject to duplicative regulation by this Commission and by state commissions.

(3) That the public interest may require that in the circumstances applicable to Washington the Commission permit the provisions of Section 7(f) to be invoked.

(4) That the operations of Washington appear to differ in essential respects from those of the above-mentioned applicants.

(5) That formal hearings should be held to determine whether or not the Commission should prescribe a service area for Washington, and, if so, what proper geographical limitations should be accorded such a service area.

736-330—64——90

The Commission orders:

(A) That those applications filed by all of the above-mentioned applicants other than Washington be dismissed.

(B) That pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Power Commission by Sections 7 and 15 of the Natural Gas Act, and the Commission's Rules of Practice and Procedure a hearing be held on July 16, 1962 at 10:00 A.M. (EDST), in a hearing room of the Federal Power Commission, 441 G Street, N.W., Washington, D. C., concerning the matters involved in and the issues noted above.

(C) Protests or petitions to intervene may be filed with the Federal Power Commission, Washington 25, D. C., in accordance with the Rules of Practice and Procedure (18 CFR 1.8 or 1.10) on or before July 9, 1962.

PACIFIC POWER AND LIGHT COMPANY, DOCKET NOS. E-7024 and E-7025

[FURTHER DISSENT BY COMMISSIONER MORGAN, ISSUED DECEMBER 7, 1962]*

MORGAN, Commissioner, *dissenting further:*

On March 28, 1962, *supra* p. 623, the Commission published orders in these dockets authorizing, as of that date, the issuance of securities for the purpose of financing a number of projects, including a particular transmission line from Klamath Falls, Oregon to Round Mountain, California which was, and remains, a highly questionable undertaking. Because of the importunities of the applicant and its associates in the financial community, the majority of this Commission were anxious to issue their order on March 28, without waiting for my dissent to be prepared, and as noted in the order I consented to that arrangement.

Because the order was effective as of March 28 and time for appeals for reconsideration or a hearing was running, I prepared my dissent as rapidly as possible, filed it with the Secretary of the Commission on April 3, and on that date distributed copies to the Governors, Senators, Congressmen and Public Utility Commissions of the states involved so that they might have prompt understanding of the important questions bearing on the public interest which theretofore had been obscured, both by the Commission's earlier "public notice" and by the order.

Acting under instructions not concurred in by me, the Commission's Secretary thereafter withheld my dissent from publication by the Commission while the majority prepared an opinion attempting to explain their position in the case. After post-dating it to April 12, the Secretary published my dissent on that date, and the majority opinion was published five days later, on April 17, while I was in Canada fulfilling a speaking engagement. This procedure, involving the post-dating of my dissent which had not been agreed to by me, created a situation giving the unavoidable impression that the dissent and the majority opinion had been exchanged for examination by the respective authors prior to publication, and that arguments made in the majority opinion and unanswered in the dissent were either unanswerable or were acceptable to me.

That any such impression can only be wholly false is clear from the foregoing statement of the facts.

Further, as I shall show, the focus of the majority opinion was so narrowly directed toward rationalization of the majority's position, rather than toward the public interest, that it repeatedly distorted the facts, the law, and common

*Initial dissent printed *supra*, p. 631.

logic and, as an end result, virtually emasculated Section 204 of the Federal Power Act which sets forth the Commission's responsibilities with respect to security issues. Since this was the first and only occasion on which the Federal Power Commission has ever expatiated on its powers and duties under Section 204, this unfortunate series of circumstances has resulted in publication of a majority opinion virtually repealing that portion of the Federal Power Act, while serving as a precedent for nonfeasance in the future even more scandalous if possible, than that of the past.

In the months which have intervened since publication of the majority opinion it has already served as a reference-guide for examiners, for staff members, and for Commissioners themselves who wish to avoid the duties and responsibilities in service of the public interest spelled out clearly by the Congress in the Federal Power Act.

In these circumstances I have the unavoidable duty, in behalf of the public interest, of commenting further in this matter. In doing so it is not my purpose to prolong or exacerbate the controversy, but to bring all aspects of this matter into proper perspective for the benefit of those who may refer to this case and its important issues in the future.

In an attempt to explain their refusal to discharge a duty Congress assigned this Commission, my colleagues have repeatedly misstated my position. Contrary to their claim, I never suggested that "the Commission should have withheld its approval" of and "should have scheduled a hearing" on a $55 million security issue, "merely because a small fraction of the proceeds [estimated by the majority at $1.5 million, or 2.7% of the total issue] are to be devoted to the construction of facilities * * * for a future use which may not materialize."

Throughout our deliberations, as my colleagues well know, I raised no question regarding the undertakings to be financed with the bulk of the issue. I was concerned, and I remain concerned, solely with the question of whether or not the expenditure of an estimated $1.5 million to enlarge the proposed Klamath Falls-Round Mountain tie-line is compatible with the public interest. I was unable, and I remain unable, to state the confines of that concern more clearly than I did in my first dissent, viz:

> It is * * * impossible to reject the line out of hand as being uneconomic, imprudent or otherwise incompatible with the public interest. There simply is no record on which to base either approval or rejection. I therefore have not advocated rejection of the project in the present proceeding and I do not advocate rejection now.
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> * * * * * * *
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> What I have advocated, and what I believe is clearly required by Section 204 (a), (b) and (c) of the Federal Power Act, is careful investigation and genuine opportunity for a hearing to determine whether the line is "compatible with the public interest" * * *

As this was the sole and separable question of the case, its determination did not require us to delay the remainder of the issue. The sections of the Act referred to above specifically give us the power to separate a single project for detailed investigation; to withhold approval of the expenditure of capital for such a project pending completion of the investigation; and to approve the issuance of capital securities and the expenditure of the proceeds on all *other* projects while such an investigation takes its course. That is the procedure—and it is the *only* procedure—which I advocated in this case.

Regardless of the "politically controversial" nature of such an inquiry, our statutory responsibility and oath of office require us to consider questions which

can only be answered by such an inquiry. The majority's obdurate refusal to inquire cannot be concealed by distorting my position.

But the more serious result of the majority's position is not their refusal to determine whether "the construction of facilities * * * for a future use which may not materialize" is "compatible with the public interest." Nor is it the majority's refusal to define or even discuss "the public interest" as a standard. The more serious result is that—acting on behalf of the Federal Power Commission, and in the first and only exposition this Commission ever made of Section 204—the majority have totally discarded "the public interest" as a standard, despite its unobscurable presence in the statute!

Section 204(a) clearly and with no trace of ambiguity states that before it may approve a security issue this Commission must satisfy itself that the specific undertaking to be financed—

(1) is lawful, and

(2) that the company is legally authorized to perform it, and

(3) that its performance "*will be compatible with the public interest,*" and

(4) that it will be consistent with the proper performance of public utility service, and

(5) that it will not impair the company's ability to serve as a public utility.

As each of these constitutes an independent standard, we are legally forbidden to approve an issue unless we can find, in fact as well as in fine-spun legal theory, that the proposed undertaking meets *each* test.[1]

Obviously, the fact that Congress refused to prescribe an alternative standard—one under which the Commission could have approved or disapproved an undertaking in its discretion—in no way diminishes the Commission's *duty* to determine whether a proposed issue meets the five standards Congress *did* prescribe. Nor does it diminish the Commission's authority and *duty* to disapprove an issue if the undertaking fails to meet any one of the five standards, each of which has a separate efficacy.[2]

In their anxiety to avoid decisional responsibility, the majority have perverted the public law. The first two and one-half pages of their statement describe the application and staff's "careful examination" thereof. Then, after explaining for three pages that the test of "public convenience and necessity" is more discretionary than the test of "the public interest," they rule that we need not apply "the public interest" test because Congress rejected the discretionary test of "public convenience and necessity"! Specifically, the majority opinion rules

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[1] The Commission, of course, must make the additional finding that "such issue * * * is reasonably necessary or appropriate" for an undertaking if it satisfies each of the five prior standards.

[2] As introduced, the bill that contained what became Title II of the Federal Power Act (S. 1725 and its House companion H.R. 5423, 74th Cong. 1st) made no reference to "the public interest" whatsoever, or to any of the other standards, in what is now Section 204 (bill Section 206).

Instead, the bill provided at Sec. 204 (of the original) that: "No public utility shall undertake the construction of or extension of any facilities * * * unless and until there shall first have been obtained from the Commission a certificate that the present or future public convenience and necessity require or will require such new construction * * *." As this authorized the Commission to exercise precedent, unrestrained certificating authority over *all* utility construction for interstate purposes, the securities section merely stated that utilities could only issue securities for authorized purposes.

But the Senate and House Commerce Committees chose not to vest unconfined certificating power in this Commission. Accordingly, they deleted the certificating section in its entirety, and inserted five specific standards in the securities section instead. (See S. 2796, in the nature of a substitute for S. 1725, as reported by each Committee and as passed.)

that, "in testing a security issue by the statutory standard," the Commission need only satisfy itself that the specific undertaking to be financed—

(1) is lawful,
(2) that the company is legally authorized to perform it, and
(3) that it will not impair ("squander") the company's ability to serve as a public utility.

As can be seen, this ruling is in flat and flagrant opposition to the law.

The remainder of the majority's statement consists of a series of question-begging assertions that this Commission is not empowered to determine whether a publicly-owned interconnection should be constructed (a determination I have never suggested we should or could make), or whether the company's proposed interconnection should be used to transmit surplus Bonneville power to the Pacific Southwest (another determination never suggested by me), plus an assertion that applicant's proposal is not "totally improvident."[3] It concludes with references to the desirability of an effective regional tie-line, the alleged "harmony" of applicant's proposal with certain of the Bonneville Power Administration's engineering recommendations, and an explanation (which does not explain) why the Notice herein did not give notice.

The majority refused to consider, discuss, or acknowledge—and labored to obscure—the only question of the case: namely, whether or not it is in "the public interest"[4] for a company, in the face of an effective prohibition against the export of surplus Bonneville power and in order to protect its private monopoly position, to expend capital underwritten by the ratepayers in a risky attempt to prevent the construction of an admittedly needed extra-high-voltage regional intertie by the construction of a designedly inferior substitute. Management here, as in all similar cases, obviously considers the risks justified as a means of achieving the ends chosen by management; but the question is whether these means or these ends should be imposed on the ratepayers who must ultimately pay the bill. Our duty is to answer that question. And abdication is not an acceptable substitute for a duty discharged.

In an attempt to extract from the majority some sort of lucid exposition of their refusal to answer the question I included the following passage in my dissent:

> Another favorite thicket of the utility lawyer defending practices such as those under discussion here is the argument that no interference with an enterprise such as this one is proper because the impact of the actions complained of is not sufficient to bankrupt the company even if the worst

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[3] The majority tested the proposal by (only) three standards. It says the question "is whether from an economic standpoint * * * an investment incontrovertibly within the lawful corporate purposes of the Applicant—represents a totally improvident business decision." But the majority did not apply the economic test either, having previously ruled that "whether [a publicly-owned] interconnection would * * * remove any economic justification for Applicant's proposed expansion * * * [is] not for us to decide." Instead, as a substitute for the investigation it refused to make, it merely provided a series of hollow official recitals, such as: "we have no reason to think" that the investment would be "totally improvident"; "this Commission estimated only last January that the demand for electric energy in 1980 will be 3.75 times the requirements in 1960"; and so on. This orotund approach will not prevent undertakings "which make *impossible* the proper and *most* economic performance of public utility functions." (Sen. Rept. 621, 74th Congress, emphasis supplied.) In sum, the majority declined to scrutinize the matter at all.

[4] Apart from its quotation of the statute, and its attempt (both footnoted) to obscure the court holding that says this Commission must require "full disclosure of all material facts" before it can find a proposed undertaking "compatible with the public interest," the majority barely mentions "the public interest" standard.

consequences were to ensue, and the effect upon the individual rate-payer, while not exactly a happy one, would not be disastrous.

This begs the question and raises a smokescreen of sophistry into the bargain. There is a principle involved here, and a supremely important one. How can we condone practices on a limited scale which, if indulged on a larger scale, would unquestionably threaten the solvency of an entire utility system? Where is the line of demarcation beyond which 'tolerable' practices become intolerably dangerous?

Here too the respected regulatory agencies have refused to be led down the primrose path. There are industries, particularly in the extractive mineral field, wherein gambling is such an essential and customary part of their business practices that the courts have, without prejudice, likened them to a poker game. The electric utility industry has never been considered one of these. It should not become one under the aegis of the Federal Power Commission.

The majority's response to this was dramatic, if nothing else. After boldly retreating from one of the plain standards set up by Section 204(a) of the Act (requiring us to "find," before approving an issue of securities, that the project on which the proceeds are to be expended will not "impair" the performance of public utility service), the majority erected their own standard in its place by fancifully embroidering the standard set up by Congress. This new standard turned out to be a banner with a strange device indeed. Under it the majority see no need to examine a particular project unless it is "so improvident, frivolous and speculative that it threatens to squander the corporate substance without reasonable hope of return" or is "a totally improvident business decision." One can only predict that snow and ice will prevail in the nether regions for many years before the members of this Commission discover any need to venture forth in battle for the public interest under that banner—nor is it altogether impossible that this very prediction played a part in the design of the new standard.

The background facts, as evident to the majority at the time they wrote their opinion as now, clearly indicated that this proposal might very easily serve to prevent the distribution and sale of electric power at the lowest possible cost to the public of the Pacific Coast regions.[5] Obviously, a proposal which on its

[5] The realities, "extra record" though they necessarily must be (there being no record), were and remain as follows: (a) the export of seasonally-surplus Bonneville power to California markets is necessary to preserve the continuance of low Bonneville rates; (b) before it can be exported, legislation is probably necessary to prevent the preference clause from operating in such fashion as to create chaos in the existing BPA marketing area; (c) upon the enactment of such legislation, passed by the last Senate but not considered by the House, an extra-high-voltage transmission line, planning funds for which have been appropriated, may be constructed to convey surplus Bonneville power to California, and surplus Central Valley Project power to the Northwest; (d) the purpose of the proposed substitute line is to foreclose later construction of the designedly superior Federal line; (e) the inferior line has not been made available to wheel surplus power between Bonneville and California; (f) no demonstration has been made that it will effectively integrate the two power-producing and marketing regions; (g) the success of applicant's grand design may force an increase of Bonneville rates; (h) this Commission must approve Bonneville's rates; and (i) those rates must be set at levels designed "to extend the benefits of an integrated transmission system and encourage the equitable distribution of the electric energy developed at * * * Bonneville," 16 USCA 832c. A complete discussion of each of these elements appears in the documents cited in footnote 2 at dissent page 633; and again in the hearings on S. 3153 in the 87th Congress before the Senate Subcommittee on Irrigation and Reclamation, and in hearings on the Bonneville inter-tie planning funds before the House and Senate Appropriations Committees. Some of these matters lie within our jurisdiction and some do not. But all of them affect and are affected by the public interest. An understanding of them is necessary to an understanding and identification of the public interest.

face raises the possibility that it may militate against "an abundance of electricity at the lowest possible cost," cannot be *presumed* to be "compatible with the public interest."[6] Those background facts plainly signaled a situation that should be investigated thoroughly, and set for hearing if necessary, for the purpose of determining whether the operation of the undertaking, *as proposed*, would be "compatible with the public interest" and "consistent with the proper performance . . . of services as a public utility," or could be made "compatible" and "consistent" therewith by the exercise of our conditioning power.[7]

The standard of "the public interest" is not surplusage or Congress would not have placed it in the statute. Its meaning is contained within the four corners of the Act of which Section 204 is a part (not the railroad law). Its statutory environment shows that the standard of the "public interest" by which the subject proposal must be tested, and with which it must be "compatible," is that method of "interconnection and coordination" which will assure, or at least not frustrate or preclude, "an abundant supply of electric energy * * * with the greatest possible economy and with regard to the proper utilization and conservation of natural resources."[8] As a matter of fact, its legislative history shows that the attainment and safeguarding of the public's interest in this particular matter was the primary reason for enacting Title II of the Federal Power Act. Senate Report No. 621 of the 74th Congress made this unequivocally clear. It said—

> The necessity for Federal leadership in securing planned coordination of the facilities of the industry which alone can produce an abundance of electricity at the lowest possible cost has been clearly revealed in the recent reports of the Federal Power Commission, the Mississippi Valley Committee and the National Resources Board * * * The new part 2 of the Federal Water Power Act seeks to bring about * * * regional coordination * * *

The "precise nature of the interests" that should have been "* * * safeguarded by this Commission in passing upon * * *" the subject application,[9] therefore, is the public interest in an "abundance of electricity at the lowest possible cost," and calls for careful scrutiny of any undertaking under our jurisdiction which may be incompatible with, or designed to prevent, the attainment thereof.

In addition to several misstatements of my position herein, the majority employ a variety of additional devices to justify their somewhat self-conscious refusal to consider this matter. First they say "we should not attempt to substitute our judgment for that of management." The answer is that Congress long ago found that management decisions in the electric power field often are contrary to the public interest; and that Congress established and directed this Commission to substitute its judgment for all management decisions that are not compatible with the public interest.

Next, the majority say they did not feel that a hearing would "illuminate any material issue." The answer to that is that our scheme of Government, including the Federal Power Act, presumes that the facts upon which *decisions affecting major issues of public policy* must be based are rarely known until a public hearing is held in which all interested parties may participate; and that such decisions should not be made *in camera* and without public notice. Pre-

[6] The issue is not that applicant failed to demonstrate that its proposal will "promote" the public interest or provide a "public benefit," *Pacific Power & Light* v. *FPC*, *infra*. The question is whether applicant's undertaking "will be compatible with the public interest" as defined by the entirety of the Federal Power Act.

[7] "Section 204(b) The Commission, after opportunity for hearing, may grant any application under this section in whole or in part, and with such modifications and upon such terms and conditions as it may find necessary or appropriate, * * *."

[8] Sec. 201(a) and Sec. 202 (a)–(d).

[9] *Pacific Power & Light* v. *Federal Power Commission*, 111 F. 2d 1014 at 1017 (1940).

sumably the countless public and private officials who journeyed to Washington, both before and after the majority acted on this matter, for the sole purpose of testifying before Congress for and against the proposed Federal line would have had at least a few words to offer, if a hearing had been held regarding the extent to which the substitute line was, or by our conditioning power could be made, "compatible with the public interest."

Next, the majority say they did not hold a hearing on the substitute line because it involved "political and policy" considerations which this Commission cannot consider. The answer is that the Federal Power Commission is a political entity; its seats are occupied by political appointees; and they serve for the purpose of deciding matters affected by and affecting public policy. If this is a bad thing, which I deny, it is very late in the game to begin worrying about it now.

Next, the majority say they did not hold hearings because "no objections were raised to the proposed issue." The answer, as the majority explain, is that the public and its officials were not notified.

Next, the majority say that the Chairman of the Washington Utilities and Transportation Commission withdrew the strong request for safeguarding conditions which he immediately filed after learning that, in this innocuous "securities" matter, the FPC proposed to determine whether the substitute line was "compatible with the public interest." Specifically, the majority say that his telegram was "superseded and withdrawn" by a later letter. The answer to this is that it is simply not true. No such letter is in the docketed files on this matter, and it is hard to see how one ever could have been, because the Chairman of the Washington Utilities and Transportation Commission never wrote such a letter.

Next, the majority say that a hearing would have been inappropriate because "procedures for considering securities issues must be expeditious." (But they "reject" any suggestion that their expedition was indistinguishable from haste.) The answer is that Congress directed this and other regulatory agencies to hold hearings, if necessary, to determine whether an undertaking to be financed with the proceeds of security issues is "compatible with the public interest"; and that other agencies do so.

Finally and principally, the majority seek to clothe their refusal to investigate in those respectable outer garments which, though threadbare, are sought after more avidly than sables in situations such as this. I refer to legalisms. Specifically the majority allege that, because the Interstate Commerce Commission interprets Section 20 (a) of the Transportation Act of 1920 narrowly, this Agency must therefore interpret Section 204 (which is patterned after Section 20 (a)) in a narrow fashion. Arguing their point, the majority quote "the leading historian" of the ICC as stating that the: "* * * dominant purpose [of Section 20 (a)] was to maintain a sound structure for the rehabilitation and support of railroad credit * * * "

There are several answers to this claim, but two will do.

(1) In the first place, when they issued their opinion the majority refrained from saying that it was Sharfman they were quoting; or from what part or portion of his massive multi-volume work on the ICC they excerpted the interior portion of one paragraph which formed their quotation. Had they done so,[10] they would have enabled their audience to find quickly that in the very next paragraph, Sharfman explains that—

> The considerations set up for the Commission's guidance are stated in very general, and somewhat vague terms. The Commission is directed to ap-

[10] Specifically, I. L. Sharfman, the Interstate Commerce Commission, Vol. 1 at p. 190.

prove the application and authorize the proposed transaction only if it finds it to be, first, for some lawful object within the carrier's corporate purposes, *compatible with the public interest*, which is necessary or appropriate for or consistent with the proper performance of service to the public as a common carrier and will not impair its ability to perform that service, and second, reasonably necessary and appropriate for this purpose. It thus appears that *large discretionary control is vested in the Commission* not only over the amount and character of new issues of railroad securities and of new assumptions of financial responsibility, but *over the uses to which the proceeds of securities are to be put* and over the direction of intercorporate agreements involving financial liabilities. In other words, *the purposes* as well as the expedients of permanent financing *are subjected to the Commission's approval and authorization, with provision for following through the disposition of the proceeds.* In order that essential financial projects may not fail for want of complete compliance with the statutory standards, the Commission is empowered not only to grant or deny any particular application, *but to grant it in part and deny it in part*, or to grant it with such modifications and upon such terms and conditions as it may prescribe. [Emphasis supplied.]

(2) The second answer to the majority's misreading of the law on this matter, is that the Interstate Commerce Commission has the power to issue certificates of convenience and necessity, and in the exercise of that power it holds extensive hearings before approving each certificate application for railroad construction. Consequently a proposed construction undertaking has been thoroughly investigated (under a different section of the Act) before that Commission is called upon to approve the issuance of securities to finance it, and the results of that prior investigation substitute for or supplement the investigation that it makes under Section 20(a). In other words, the scope of an actual inquiry by the ICC under Section 20(a) is not necessarily a measure of the scope of the inquiry authorized thereby; and that Commission's practice in no way limits the scope of the inquiry we are authorized and directed to make under the statutory counterpart of Section 20(a). The following excerpts from the decisions of the ICC itself make this clear:

> We are required to make investigation of securities before authorizing their issue.[11]
>
> Our powers, in the public interest, to grant or withhold approval of security issues are broad.[12]
>
> In any application to us for authority to issue securities, we are bound to measure the proposal by the test of the public interest in whatever phase that interest may appear to be affected.[13]

And, from the Supreme Court of New York:

> Whatever may be the language used in its decisions, it is clear that when the [Interstate Commerce] Commission is called upon to approve the issuance and sale of securities under § 20a it has felt itself free, and properly so, to exercise its own independent judgment for that of the directors where in its opinion the public interests would best be served thereby. * * * Obviously, it would be futile [for an applicant] to propose a security issue which the Commission would be bound to disapprove as

[11] *In the Matter of Wheeling & Lake Erie Railway Company*, 67 ICC 293 (1921).
[12] *In the Matter of New York, Chicago, and St. Louis Railroad Company*, 79 ICC 581 at 585 (1923).
[13] *Stock of New Jersey, Indiana & Illinois R.*, 94 ICC 727 at 729 (1925).

not "compatible with the public interest" or with the proper performance by it of service to the public.[14]

In sum, the majority's attempt to obscure the unobscurable intent of Section 204 of the Federal Power Act by an overlay of legalisms simply will not do.

Neither will the attempt, although it is understandable, to brush aside the Virginia commission's refusal to shirk its statutory duty in a similar situation. In that case the Virginia commission refused to approve an issue of securities by an electric utility on the ground that the facilities to be financed thereby would not be "in the public interest." If I understand their position correctly, the members of the majority imply the case is "inapposite" because that Commission possessed the power to issue or deny certificates of convenience and necessity when it held that the issue was not "in the public interest" *as determined under its security-approval statute!* The majority have misread the case.

The case involved the 1934 Public Securities Law of Virginia (7 Va. 56–75). "The 1934 statute is concerned *only* with the issuance of securities," the Virginia commission explained, and it "says this commission *must* grant the authority applied for unless it finds that the loan is not 'reasonably necessary' to carry out one or more of the [public utility] purposes set forth in the application" (emphasis supplied). The Commission then went on to find that the application "filed *December 12, 1949*" and on which "public hearings began *April 24, 1950*," was not "in the public interest." [Emphasis supplied.]

It is true that the Virginia Code now provides the Virginia commission with the (additional) power to issue certificates of convenience and necessity. Specifically, it states at Section 50–265.2 that—

> It shall be unlawful for any public utility to construct, enlarge or acquire, by lease or otherwise, any facilities for use in public utility service * * * without first having obtained a certificate from the Commission that the public convenience and necessity require the exercise of such right or privilege. Such certificate shall be issued by the Commission only after formal or informal hearing and after due notice to interested parties.

But below, at Section 56–265.8, the law unequivocally states that such certificating authority—

> * * * shall not apply to or in any way affect any proceeding before the * * * Commission on or before *July first, nineteen hundred fifty.* [Emphasis supplied.]

One has only to read that date and compare it with the filing date and date of commencement of hearings before the Virginia commission to agree with my statement that in the particular case, the Virginia commission was "armed only with the power of approval or disapproval over security issues" and that it "used that power to prevent construction." The majority in this case were not willing to use that power to initiate an inquiry. *There* is the difference between the two cases.

The majority opinion includes numerous statements irreconcilable with the facts, which I have neither the time nor the inclination to comment on in detail. The following sentence is selected only as an example. In it the majority assert: "The record indicates that the [applicant's] new intertie will provide for the exchange of energy between the two systems and *will be available for use by the Bonneville Power Administration or other utility companies in the Pacific Northwest.*"

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[14] *Casey* v. *Woodruff, et al.*, 49 N.Y.S. 2d 625 at 640 (1944).

In the first place there was and is no "record" indicating the foregoing, or, for that matter, anything else. In the second place there is only one intelligible reading of that sentence, particularly the portion I have emphasized. It indicates that P.P. & L. and P.G. & E. have offered to allow the use of excess line capacity *by other public and private power agencies* for wheeling their own power to their own wholesale customers over the companies' line. I have made every possible effort to substantiate this statement, including discussions with company officials, and every effort has ended in a finding that the statement was and still is in flat contradiction of the facts. The companies have, indeed, offered to be the sole *purchasers* and *sellers* of power between the two regions but they have *not* made the line available to other agencies in a genuine wheeling agreement. At this date there appears to be every reason to believe they never will. Let me add that the public interest would probably benefit materially if this prognostication should later prove to be wrong, but as of now it is very far from wrong. Construction of the line has not yet begun, more than eight months after hurried approval of securities, because of the companies' inability to obtain permits to build across public lands, and there is reason to believe that the permits are being withheld as the direct result of the companies' refusal to share costs and benefits of the line in the public interest. This is not the impression conveyed by the sentence I have quoted from the majority's opinion.

The foregoing is set forth as a caution to attorneys and scholars reading this case, so that they may examine asserted facts with care. As can be seen, some of them are not facts.

The majority make much of the undeniable fact that our jurisdiction over security issues of electric companies is limited by the peculiar wording of the Federal Power Act. It is certainly true that many electric companies are required to expose their security issues—and the projects to be financed thereby—to our scrutiny either not at all or only because of rather irrelevant factors having to do with place of incorporation and the like. But that is no reason for us to refuse to exercise the jurisdiction, spotty and sketchy though it may be, which Congress *has* seen fit to give us, and which we could and should have exercised in this case. Nor is there any reason in the public interest for our failing to call the attention of Congress to the inadequacies of the statute which the majority opinion outlined. No move has been made toward doing so in the eight months since the majority opinion was published. One finds it hard to escape the conclusion that the majority failed to take action in this case not because they lacked the power but because they preferred inaction then and have continued to prefer it since.

The same is true with respect to our lack of certificating power over such newly important developments as long-distance extra-high-voltage regional interties. I will not lengthen this dissent by a recital of the many ways in which the new transmission technology may now affect the public interest for good or ill in this vital field. The very case here discussed is a fairly illustrative, though by no means a complete, example. Suffice it to say that the technological and economic circumstances affecting the public interest are now radically different from those in which the Congress, in 1935, decided not to grant certificating authority to us. Bills which would close this gap for the protection of the public were introduced in the last session of the Congress. We have been asked to support those bills and I believe we should. But in the eight months since publication of their opinion the majority herein have made no move and have spoken no word in support of those bills despite the present inadequacies of the statute which they themselves have pointed out.

In this case we have been faced with a clear choice: like the Virginia commission in the case cited above we could have used the tools we already have, inadequate though they might prove to be in *other* cases, while asking that we be provided with the additional tools necessary for full protection of the public interest in *all* cases. Or we could, as the majority have done with superb illogic, point to the missing tools (and some which are *not* missing) as an excuse for refusal to use the ones we have, and then conspicuously refrain from asking that the missing tools be supplied.

The latter course was chosen by the majority in this case. I respectfully suggest that it is not good enough. The public interest, like the law available to us but not employed in this case, looms large to those who search for it. If the public is to be given the protection from monopoly which it deserves and expects, the law must eventually match the public interest. I believe the law adequately enabled us, in the public interest, to dispose of the issues posed by this case. In the future the law must be changed so that it matches the public interest in *every* case, and ***the law must be used.***

APPLICATIONS OF PRODUCERS OF NATURAL GAS FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY DISPOSED OF DURING THE PERIOD OF JANUARY 1, 1962 THROUGH JUNE 30, 1962; SERVICE BEGINNING SUBSEQUENT TO JUNE 7, 1954

NEW SERVICE CERTIFICATES

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
M. D. Abel, et al.:					
CI62-600 El Paso Natural Gas Co.	Reagan*	Tex	Upton	5 25 62	Iss.
William M. Aber, Operator, et al:					
CI62-357 Texas Eastern Transmission Corp.	Sheridan	Tex	Colorado	4 17 62	Iss.
Acco Oil & Gas Co., Operator, et al.:					
CI61-1183 Tenessee Gas Transmission Co.	East Bernard Area	Tex	Wharton	1 29 62	Iss.
K. S. Adams, Jr.:					
G-16305 Phillips Petroleum Co.	Panhandle	Tex	Gray	3 26 62	Iss.
Afroma Oil & Gas Co., Inc.:					
CI62-12 United Gas PipeLine Co.	Riggs Area	Tex	Goliad	2 21 62	Iss.
Aladdin Petroleum Corp.:					
G-18398 El Paso Natural Gas Co.	Blanco	N. Mex	San Juan	5 23 62	Iss.
Alamo Corp.:					
CI61-1612 Panhandle Eastern Pipe Line Co.	Richfield	Kans	Morton	1 8 62	Iss.
Wm. H. Allen, et al.:					
CI62-388 Colorado Interstate Gas Co.	Mocane	Okla	Beaver	5 23 62	Iss.
CI62-390 Northern Natural Gas Co.	Morrow	Tex	Ochiltree	3 26 62	Iss.
Allied Material Corp., Operator:					
CI61-602 Northern Natural Gas Co.	Bernstein-Cherokee	Tex	Hansford	5 7 62	Iss.
Manuel Alvarez, Jr.:					
CI62-662 Hope Natural Gas Co.	Collins Settlement District.	W. Va	Lewis	5 29 62	Iss.
Ambassador Oil Corp.:					
CI61-183 Lone Star Gas Co	Tit-Tah Lease	Okla	Stephens	5 7 62	Iss.
CI61-1190 Panhandle Eastern Pipe Line Co.	Undesignated	Okla	Beaver	1 29 62	Iss.
Amerada Petroleum Corp.:					
CI61-1091 Michigan Wisconsin Pipe Line Co.	Northwest Oakdale.*	Okla	Alfalfa*	3 7 62	Iss.
CI61-1650 Lone Star Gas Co	West Velma	Okla	Stephens	3 23 62	Iss.
CI62-593 Lone Star Gas Co	Stage Stand	Okla	Stephens	4 17 62	Iss.
American Petrofina Co. of Texas:					
CI61-672 Trunkline Gas Co	Hidalgo	Tex	Hidalgo	5 25 62	Iss.
Anadarko Production Co.:					
CI61-742 Panhandle Eastern Pipe Line Co.	Hugoton	Kans	Stevens	5 25 62	Iss.
CI61-1679 Panhandle Eastern Pipe Line Co.	N. Richland Center	Okla	Texas	5 23 62	Iss.
CI61-1803 Panhandle Eastern Pipe Line Co.	Hugoton	Okla	Texas	5 23 62	Iss.
CI62-89 Panhandle Eastern Pipe Line Co.	Hugoton	Kans	Stevens	5 23 62	Iss.
CI62-257 Panhandle Eastern Pipe Line Co.	Peters	Kans	Seward	5 23 62	Iss.
CI62-356 Northern Natural Gas Co.	Hugoton	Kans	Stevens	5 31 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Anadarko Production Co—Con.					
CI62-396 Colorado Interstate Gas Co.	Mocane	Okla.	Beaver	5 23 62	Iss.
CI62-432 Cities Service Gas Co.	Hugoton	Kans.	Morton	5 23 62	Iss.
CI62-584 Northern Natural Gas Co.	Southwest Camp Creek.	Okla.	Beaver	5 7 62	Iss.
R. G. Anderson:					
CI61-1104 Michigan Wisconsin Pipe Line Co.	Laverne	Okla.	Harper	4 17 62	Iss.
H. C. and Gertrude B. Andrewski:					
CI61-1678 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
Apache Corp.:					
CI63-809 Panhandle Eastern Pipe Line Co.	N. E. Greenough	Okla.	Beaver	6 4 62	Iss.
Appalachian Land & Development Co.:					
CI61-1465 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	2 21 62	Iss.
Appell Petroleum Corp.:					
CI61-1233 Altex Corp.	W. Alice	Tex.	Jim Wells	5 23 62	Iss.
Appell Petroleum Corp., Operator, et al.:					
CI61-610 Coastal States Gas Producing Co.	Ed Vela	Tex.	Hidalgo	5 23 62	Iss.
CI61-880 South Texas Natural Gas Gathering Co.	Witted	Tex.	Hidalgo	5 23 62	Iss.
CI61-1462 Altex Corp.	West Alice	Tex.	Jim Wells	5 23 62	Iss.
CI61-1578 Altex Corp.	Tom Graham	Tex.	Jim Wells	6 4 62	Iss.
CI62-573 Texas Eastern Transmission Corp.	Englehart	Tex.	Colorado	4 17 62	Iss.
Paul H. Ash, et al.:					
CI61-1767 Equitable Gas Co.	Court House District.	W. Va.	Lewis	2 21 62	Iss.
CI62-126 Equitable Gas Co.	Court House District.	W. Va.	Lewis	5 29 62	Iss.
CI62-272 Equitable Gas Co.	Skin Creek District.	W. Va.	Lewis	3 26 62	Iss.
CI62-377 Equitable Gas Co.	Skin Creek District.	W. Va.	Lewis	3 26 62	Iss.
CI62-380 Equitable Gas Co.	Skin Creek District.	W. Va.	Lewis	3 26 62	Iss.
CI62-654 Equitable Gas Co.	Buckhannon District.*	W. Va.	Upshur*	5 23 62	Iss.
CI62-655 Equitable Gas Co.	Skin Creek District.	W. Va.	Lewis	5 29 62	Iss.
Ashland Oil & Refining Co.:					
G-13243 United Gas Pipe Line Co.	Cotton Valley	La.	Webster	3 26 62	Iss.
CI60-738 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Woodward*	6 29 62	Iss.
CI62-191 Natural Gas Pipeline Co. of America.	West Chester	Okla.	Woodward	5 29 62	Iss.
CI62-419 Northern Natural Gas Co.	Harper Ranch	Kans.	Clark	6 4 62	Iss.
CI62-494 Northern Natural Gas Co.	Harper Ranch	Kans.	Clark	5 29 62	Iss.
CI62-652 Northern Natural Gas Co.	Harper Ranch	Kans.	Clark	5 29 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
The Atlantic Refining Co.:					
G-10305 Skelly Oil Co.	East Lovington	N. Mex.	Lea	5 14 62	Rej.
G-10687 Reef Fields Gasoline Corp.	Jo Mill	Tex.	Borden	5 14 62	Rej.
G-11034 Tennessee Gas Transmission Co.	East Cameron Area.*	La.	Cameron*	1 22 62	Iss.
G-18572 United Gas Pipe Line Co.	Ada	La.	Bienville	3 21 62	Iss.
CI61-107 Trunkline Gas Co.	West Nona Mills	Tex.	Hardin	1 8 62	Iss.
CI61-752 Michigan Wisconsin Pipe Line Co.	Woodward Area	Okla.	Woodward*	3 7 62	Iss.
CI61-1245 Texas Gas Transmission Corp.	Calhoun	La.	Ouachita	3 23 62	Iss.
CI61-1284 Arkansas Louisiana Gas Co.	Vixen	La.	Caldwell	3 23 62	Iss.
CI61-1439 Texas Gas Transmission Corp.	Cartwright	La.	Jackson	1 29 62	Iss.
CI62-105 Northern Natural Gas Co.	North Harper Ranch.*	Kans.	Clark	3 23 62	Iss.
CI62-363 Transcontinental Gas Pipe Line Corp.	San Miguel Creek	Tex.	McMullen	4 17 62	Iss.
John J. August, et al.:					
CI62-545 El Paso Natural Gas Co.	Undesignated	N. Mex.	Rio Arriba	4 17 62	Iss.
Austral Oil Co., Inc.:					
CI62-884 El Paso Natural Gas Co.	Brown-Bassett Ellenberger.	Tex.	Terrell	5 23 62	Iss.
Kenneth M. Axelrod, et al.:					
CI61-404 Phillips Petroleum Co.	West Panhandle	Tex.	Gray	5 7 62	Iss.
Aylward Drilling Co.:					
CI61-1364 Cities Service Gas Co.	Undesignated	Kans.	Barber	1 8 62	Iss.
Aztec Oil & Gas Co.:					
CI61-1472 El Paso Natural Gas Co.	Basin Dakota	N. Mex.	San Juan	5 23 62	Iss.
Backerhouse Oil & Gas Co.:					
CI61-1580 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	1 29 62	Iss.
Bailey Gas Co.:					
CI62-176 Hope Natural Gas Co.	Baileysville District	W. Va.	Wyoming	5 29 62	Iss.
Margaret Dobbs Bain, et al.:					
CI62-340 United Gas Pipe Line Co.	Bear Creek Area	La.	Bienville	4 10 62	Wtd.
Charles E. Baker, et al.:					
CI62-514 Hope Natural Gas Co.	Central District	W. Va.	Doddridge	4 17 62	Iss.
K. Baker:					
CI61-902 Tennessee Gas Transmission Co.	Bethany	Tex.	Panola	1 29 62	Iss.
E. A. Ballengee:					
CI62-722 Sam. T. Mallison, et al., Trustee.	Murphy	W. Va.	Ritchie	5 29 62	Iss.
E. A. Ballengee, et al.:					
CI62-298 Hope Natural Gas Co.	Center District	W. Va.	Calhoun	5 29 62	Iss.
Barber Gas Operations, Inc.:					
CI61-779 Cities Service Gas Co.	Undesignated	Kans.	Barber	5 25 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Mary Barillaro:					
CI62-886 Hope Natural Gas Co.	Central District	W. Va.	Doddridge	6 4 62	Iss.
Barnwell Production Co.:					
CI61-1614 Arkansas Louisiana Gas Co.	Vixen	La.	Caldwell*	3 23 62	Iss.
Roy G. Barton:					
G-19677 El Paso Natural Gas Co.	Denton	N. Mex.	Lea	5 1 62	Iss.
Perry R. Bass, Operator, et al.:					
CI62-705 El Paso Natural Gas Co.	Brown-Bassett	Tex.	Terrell	5 29 62	Iss.
Bear Run Oil & Gas Co.:					
CI62-213 Equitable Gas Co.	Hackers Creek District.	W. Va.	Lewis	5 29 62	Iss.
Belco Petroleum Corp.:					
CI60-475 El Paso Natural Gas Co.	Tip Top-Hogsback	Wyo.	Sublette*	6 11 62	Iss.
CI62-55 Mountain Fuel Supply Co.	Birch Creek Area	Wyo.	Sublette*	2 21 62	Iss.
Rodney B. Belknap:					
CI62-617 Hope Natural Gas Co.	Otter District	W. Va.	Braxton	5 29 62	Iss.
J. C. Benedict:					
CI61-1613 Northern Natural Gas Co.	Fellsburg	Kans.	Edwards	1 8 62	Iss.
Beneficial Oil Co.:					
CI61-729 El Paso Natural Gas Co.	Tip Top-Hogsback	Wyo.	Sublette*	6 11 62	Iss.
Benin Oil Co., Operator, et al.:					
CI62-343 Texas Eastern Transmission Corp.	East Lewisburg	La.	St. Landry	5 29 62	Iss.
Richard H. Bennett:					
G-18724 Equitable Gas Co.	Rosedale, Center District.	W. Va.	Gilmer	5 1 62	Iss.
CI62-456 Equitable Gas Co.	Howes Wells, Warren & Buckhannon.	W. Va.	Upshur	5 23 62	Iss.
Davisson A. Benson, Jr.:					
CI62-117 United Fuel Gas Co.	Henry District	W. Va.	Clay	5 29 62	Iss.
Benson-Montin-Greer Drilling Corp.:					
CI61-156 El Paso Natural Gas Co.	Blanco*	N. Mex.	Rio Arriba	2 21 62	Iss.
Berea Gas:					
CI61-681 Hope Natural Gas Co.	Grant District	W. Va.	Monongalia	1 8 62	Iss.
Bering Co., Operating Account, Operator:					
G-11617 United Gas Pipe Line Co.	South Caesar	Tex.	Bee	5 1 62	Iss.
G-12482 W. J. Riley, Inc.	White Point Area	Tex.	San Patricio	5 1 62	Iss.
Clyde Beymer, Jr.:					
G-13969 Cities Service Gas Co.	Hugoton	Kans.	Kearny	3 26 62	Iss.
CI62-560 Cities Service Gas Co.	Swain No. 1, Unit	Kans.	Kearny	5 7 62	Iss.
Big Injun Oil & Gas Co., Inc.:					
CI61-1534 Equitable Gas Co.	West Union District	W. Va.	Doddridge	1 8 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCERS, DOCKET NO. AND PURCHASERS	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Blackwell Zinc Co., Inc.:					
CI61-276 Lone Star Gas Co.	South Alma	Okla.	Stephens	3 23 62	Iss.
Blackwell Zinc Co., Inc., Operator et al.:					
CI61-1817 Northern Natural Gas Co.	Laverne	Okla.	Harper	2 21 62	Iss.
Thomas J. Blaho, Jr.:					
CI62-424 Equitable Gas Co.	Court House District.	W. Va.	Lewis	4 17 62	Iss.
Blanco Oil Co., Operator, et al.:					
CI61-82 United Gas Pipe Line Co.	Redfish Bay, Northeast.	Tex.	Nueces	1 8 62	Iss.
W. G. Blewster & Joe F. Rushton:					
CI62-718 Equitable Gas Co.	Court House District.*	W. Va.	Lewis	5 29 62	Iss.
W. G. Blewster, et al.:					
CI62-262 Equitable Gas Co.	Collins Settlement District.	W. Va.	Lewis	3 26 62	Iss.
CI62-587 Hope Natural Gas Co.	Court House District.	W. Va.	Lewis	6 4 62	Iss.
Vaughn Boatright:					
G-14722 Equitable Gas Co.	Glenville District	W. Va.	Gilmer	5 1 62	Iss.
Bodcaw Co., Operator, et al.:					
CI62-174 United Gas Pipe Line Co.	Cotton Valley	La.	Webster	6 4 62	Iss.
Bolsa Chica Oil Corp.:					
CI61-1569 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
Bonray Oil Co.:					
CI60-306 Cities Service Gas Co.	Eureka	Okla.	Grant	5 29 62	Iss.
Bonray Oil Co., Operator, et al.:					
CI62-110 Cities Service Gas Co.	West Mt. Zion	Okla.	Grant	3 23 62	Iss.
CI62-112 Cities Service Gas Co.	West Mt. Zion	Okla.	Grant	3 23 62	Iss.
John P. Booth:					
CI62-136 Northern Natural Gas Co.	Sitka	Kans.	Clark	4 17 62	Iss.
B. F. Bowman:					
G-18263 Hope Natural Gas Co.	Union District	W. Va.	Harrison	3 23 62	Iss.
Boyd & Shriver:					
CI60-359 United Natural Gas Co.	Undesignated	Pa.	Jefferson	5 1 62	Iss.
Braden Drilling, Inc.:					
G-20294 Panhandle Eastern Pipe Line Co.	Robbins Lease	Kans.	Pratt	5 29 62	Iss.
CI60-439 Panhandle Eastern Pipe Line Co.	Irwin-Vernning Unit.	Kans.	Pratt	5 29 62	Iss.
CI61-1611 Panhandle Eastern Pipe Line Co.	Undesignated	Kans.	Pratt	1 8 62	Iss.
R. J. Braden, et al.:					
CI62-772 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 29 62	Iss.
Edwin G. Bradley, Agent, et al.:					
G-16589 Panhandle Eastern Pipe Line Co.	Lerado	Kans.	Reno	5 1 62	Iss.
The Bradley Producing Corp.:					
G-19401 Natural Gas Pipeline Co. of America	Camrick S. E. Pool	Okla.	Beaver	5 29 62	Iss.
S. F. Bradley:					
CI62-763 Kentucky West Virginia Gas Co.	Big Sandy River	Ky.	Floyd	6 4 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Austin Brady:					
G-20264 Kansas-Nebraska Natural Gas., Inc.	Hugoton	Kans	Haskell	5 29 62	Iss.
Clyde J. Brannan Jr., Operator, et. al.:					
CI61-1506 El Paso Natural Gas Co.	Sonora	Tex	Sutton	2 21 62	Iss.
Brannon Gas Co.:					
CI61-431 Hope Natural Gas Co.	Washington District.	W. Va	Calhoun	1 29 62	Iss.
Victor Brannon:					
CI62-157 Hope Natural Gas Co.	Washington District.	W. Va	Calhoun	4 17 62	Iss.
Victor Brannon, et. al.:					
CI60-373 Hope Natural Gas Co.	Washington District.	W. Va	Calhoun	5 1 62	Iss.
Henry C. Breck:					
CI62-93 Equitable Gas Co	Glenville District	W. Va	Gilmer	3 23 62	Iss.
Billy Bridewell, et. al.:					
CI62-103 Texas Eastern Transmission Corp.	Appling	Tex	Calhoun	3 23 62	Iss.
Bridwell Oil Co.:					
CI61-1037 Coastal States Gas Producing Co.	Johns Area	Tex	Duval	5 23 62	Iss.
Paul Brisbin, Operator, et. al.:					
G-18001 Penova Interests	Murphy District	W. Va	Ritchie	3 26 62	Iss.
CI62-549 Penova Interest	Murphy	W. Va	Ritchie	5 1 62	Iss.
Powel Briscoe, Operator, et. al.:					
G-18333 Cities Service Gas Co.	Undesignated	Okla	Lincoln	3 26 62	Iss.
Paul L. Britton, Jr., Operator, et. al.:					
CI62-333 Lake Shore Pipe Line Co.	Clinton Sand	Pa	Erie	1 19 62	Iss.
George E. Brogan, Trustee, et. al.:					
CI61-1324 El Paso Natural Gas Co.	Devil S. Fork	N. Mex	Rio Arriba	1 29 62	Iss.
Lee J. Bronson:					
CI62-107 El Paso Natural Gas Co.	Noelke	Tex	Crockett	3 23 62	Iss.
Brookside Oil & Gas Co.:					
CI62-727 Hope Natural Gas Co.	Center*	W. Va	Gilmer*	5 29 62	Iss.
Brookside Oil & Gas Co.:					
CI62-774 Hope Natural Gas Co.	Salt Lick District	W. Va	Braxton	5 29 62	Iss.
Brown & Key, Inc.:					
CI60-816 El Paso Natural Gas Co.	Langlie-Mattix Oil Pool.	N. Mex	Lea	2 21 62	Iss.
George R. Brown, Operator, et al.:					
CI61-1250 Texas Eastern Transmission Corp.	South Lucky	Tex	Matagorda	3 23 62	Iss.
H. L. Brown, Operator:					
G-17945 El Paso Natural Gas Co.	Spraberry Trend	Tex	Regan	5 7 62	Iss.
Herman Brown:					
CI62-83 Texas Eastern Transmission Corp.	Northwest Buttermilk Slough.	Tex	Matagorda	3 23 62	Iss.

See footnotes at end of table, p. 1404.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION[1]
James G. Brown:					
CI62-220 Texas Eastern Transmission Corp.	Dial	Tex	Goliad	5 29 62	Iss.
Harvey Broyles, Operator, et al.:					
CI62-106 Texas Gas Transmission Corp.	Ruston	La	Lincoln	5 29 62	Iss.
Richard H. Brumbaugh:					
CI61-1264 Hope Natural Gas Co.	Washington District.	W. Va	Calhoun	2 21 62	Iss.
CI61-1305 Hope Natural Gas Co.	Washington District.	W. Va	Calhoun	1 29 62	Iss.
CI61-1702 Hope Natural Gas Co.	Murphy District	W. Va	Ritchie	5 29 62	Iss.
CI61-1720 Hope Natural Gas Co.	Murphy District	W. Va	Ritchie	5 29 62	Iss.
Richard H. Brumbaugh, et al.:					
CI61-1759 Hope Natural Gas Co.	Washington District.	W. Va	Calhoun	1 29 62	Iss.
Jack H. Bryant, Trustee:					
CI60-143 El Paso Natural Gas Co.	Undesignated	Tex	Nolan	5 31 62	Iss.
W. E. Burchett, et al.:					
CI62-168 United Fuel Gas Co.	Undesignated	W. Va	Mingo*	6 4 62	Iss.
B. L. Burge:					
CI62-420 Hope Natural Gas Co.	Sherman District	W. Va	Calhoun	5 31 62	Iss.
P.O. Burgy Drilling & Producing Co.:					
G-17893 Barron Kidd	Grant District	W. Va	Ritchie	5 7 62	Iss.
John H. Burkhardt and Herman Burkhardt:					
CI61-1785 Oklahoma Natural Gathering Corp., et al.	Ringwood	Okla	Major	3 30 62	Iss.
Bobby M. Burns:					
G-18366 Northern Natural Gas Co.	Hansford	Tex	Ochiltree	3 26 62	Iss.
Allen Burr, Operator, et al.:					
CI60-494 Syljo Gas Co	North Fannin	Tex	Goliad	1 8 62	Iss.
Jack L. Burrell, Operator, et al.:					
CI61-1223 Transwestern Pipeline Co.	Waha	Tex	Reeves*	2 21 62	Iss.
CI61-1224 Transwestern Pipeline Co.	Waha	Tex	Reeves*	2 21 62	Iss.
W. H. Busch, et al.:					
CI61-370 Hope Natural Gas Co.	DeKalb District	W. Va	Gilmer	5 7 62	Iss.
CI61-664 Equitable Gas Co	DeKalb District	W. Va	Gilmer	5 23 62	Iss.
CI61-1801 Hope Natural Gas Co.	DeKalb District	W. Va	Gilmer	2 21 62	Iss.
CI62-350 Hope Natural Gas Co.	DeKalb District	W. Va	Gilmer	3 26 62	Iss.
Harry D. Bush, et al.:					
G-16833 Hope Natural Gas Co.	DeKalb District	W. Va	Gilmer	3 26 62	Iss.
CI61-1196 Hope Natural Gas Co.	Murphy District	W. Va	Ritchie	3 23 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Busmore Oil & Gas Co., Operator, et al.:					
CI61-1219 Orange Grove Gas Gathering Co.	Undesignated	Tex	Jim Wells	5 7 62	Iss.
S. G. Butcher & J. L. Carey:					
G-19459 Western Gas Service Co.	Hugoton	Okla	Texas	5 1 62	Iss.
Dorsey Buttram:					
CI60-442 El Paso Natural Gas Co.	Red Wash	Utah	Uintah	6 11 62	Iss.
W. K. Byrom, Operator, et al.:					
G-18049 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex	Lea	6 4 62	Iss.
G-18050 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex	Lea	6 4 62	Iss.
G-18051 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex	Lea	6 4 62	Iss.
CI61-1549 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex	Lea	6 4 62	Iss.
C. & G. Joint Venture:					
CI62-532 Hope Natural Gas Co.	Otter District	W. Va	Braxton	5 31 62	Iss.
C. I. West Virginia Corp.:					
CI61-1126 Equitable Gas Co.	DeKalb District	W. Va	Gilmer	1 29 62	Iss.
Cabot Corp.:					
CI61-1559 Hope Natural Gas Co.	Buchanan County	Va	Buchanan	5 29 62	Iss.
CI61-1823 Bailey Gas Co.	Baileysville District	W. Va	Wyoming	5 29 62	Iss.
CI62-524 New York State Natural Gas Corp.	Whippoorwill Hollow.	Pa	Cameron*	4 17 62	Iss.
Francis E. Cain, et al.:					
CI61-442 Hope Natural Gas Co.	Barnes Run	W. Va	Calhoun	1 29 62	Iss.
CI61-1798 Hope Natural Gas Co.	Lee District	W. Va	Calhoun	2 21 62	Iss.
CI62-17 Hope Natural Gas Co.	Sheridan District	W. Va	Calhoun	5 29 62	Iss.
CI62-23 Hope Natural Gas Co.	Lee District	W. Va	Calhoun	2 21 62	Iss.
CI62-429 Hope Natural Gas Co.	Lea District	W. Va	Calhoun	3 26 62	Iss.
CI62-740 Hope Natural Gas Co.	Spencer District	W. Va	Roane	5 29 62	Iss.
Leonard Cain:					
CI61-663 Godfrey L. Cabot, Inc.	Sheridan District	W. Va	Calhoun	5 25 62	Iss.
Calder, N. Bruce and Curtis E., Jr.:					
G-13886 Northern Natural Gas Co.	West Morrow	Tex	Hansford	5 1 62	Iss.
G-19524 Natural Gas Pipeline Co. of America.	Camrick	Okla	Texas	5 29 62	Iss.
CI61-1704 Northern Natural Gas Co.	Hansford	Tex	Hansford*	1 8 62	Iss.
CI62-734 Panhandle Eastern Pipe Line Co.	Hansford	Tex	Hansford	5 29 62	Iss.
California Co., Division of California Oil Co.:					
CI61-208 Transcontinental Gas Pipe Line Corp.	Sharon	Miss	Jasper*	5 7 62	Iss

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
California Oil Co., Western Division:					
CI60-333 El Paso Natural Gas Co.	Red Wash	Utah	Uintah	6 11 62	Iss.
Calvert Petroleum Co.:					
CI60-691 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Dewey*	1 15 62	Iss.
Rodney P. Calvin:					
CI62-802 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	5 29 62	Iss.
A. A. Cameron:					
CI62-574 Cities Service Gas Co.	South Sterling Area	Okla.	Comanche	4 17 62	Iss.
Camp Oil Co., et al.:					
CI60-664 Coastal States Gas Producing Co.	Johns Field Area	Tex.	Duval	5 7 62	Iss.
CI60-742 Coastal States Gas Producing Co., et al.	Johns Field Area	Tex.	Duval	4 17 62	Iss.
Morris Cannan, Operator:					
G-15147 J. C. Adair	Alfred	Tex.	Jim Wells	5 1 62	Iss.
Morris Cannan, Operator, et al.:					
CI61-1310 Texas Eastern Transmission Corp.	Kittie	Tex.	Live Oak	1 29 62	Iss.
A. M. Carlson:					
CI60-541 Equitable Gas Co.	West Union District.	W. Va.	Doddridge	5 7 62	Iss.
CI61-1474 Hope Natural Gas Co.	Collins Settlement District.	W. Va.	Lewis	2 21 62	Iss.
CI61-1721 Equitable Gas Co.	Court House	W. Va.	Lewis	5 29 62	Iss.
CI62-766 Hope Natural Gas Co.	Collins Settlement District.	W. Va.	Lewis	5 29 62	Iss.
Carter Foundation Production Co.:					
G-17953 El Paso Natural Gas Co.	Central Langlie-Mattix.	N. Mex.	Lea	3 23 62	Iss.
Caulkins Oil Co.:					
CI62-455 Northern Natural Gas Co.	Harper Ranch	Kans.	Clark	6 4 62	Iss.
CI62-595 Northern Natural Gas Co.	Harper Ranch	Kans.	Clark	4 17 62	Iss.
Caulkins Oil Co., Operator:					
CI61-234 El Paso Natural Gas Co.	Undesignated	N. Mex.	Arriba	2 21 62	Iss.
George P. Caulkins, Jr.:					
CI60-560 El Paso Natural Gas Co.	Red Wash	Utah	Uintah	6 11 62	Iss.
Joe N. Champlin, Operator, et al.:					
CI61-1195 Panhandle Eastern Pipe Line Co.	Undesignated	Kans.	Meade	3 23 62	Iss.
Champlin Oil & Refining Co.:					
G-9761 Tennessee Gas Transmission Gas Co.	Carthage	Tex.	Panola	5 1 62	Iss.
CI61-746 Natural Gas Pipeline Co. of America.	McCormick	Okla.	Woodward	5 1 62	Iss.
CI61-1426 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Texas	2 21 62	Iss.
CI62-108 Zenith Gas System, Inc.	Davis Ranch Area	Kans.	Barber	3 23 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Chelletex Corp.:					
CI61-1371 Tennessee Gas Transmission Corp	Morales	Tex.	Jackson	1 8 62	Iss.
Christie, Mitchell and Mitchell, Agent:					
CI61-1222 United Gas Pipe Line Co.	South Slocum	Tex.	Anderson	1 29 62	Iss.
Christie, Mitchell & Mitchell Co., et al.:					
CI62-393 Valley Gas Transmission, Inc.	Buttermilk	Tex.	Matagorda	5 23 62	Iss.
Cities Service Co., Operator, et al.:					
CI61-1681 United Gas Pipe Line Co.	Magee	Miss.	Simpson*	3 23 62	Iss.
Cities Service Petroleum Co.:					
CI61-39 Panhandle Eastern Pipe Line Co.	Undesignated	Kans.	Edwards	5 23 62	Iss.
CI61-1094 United Gas Pipe Line Co.	East Texas Plant.	Tex.	Gregg	5 7 62	Iss.
CI61-1446 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Texas	2 21 62	Iss.
CI61-1664 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
CI62-26 Colorado Interstate Gas Co.	Mocane	Okla.	Beaver	5 23 62	Iss.
CI62-72 Natural Gas Pipeline Co. of America.	Camrick Southeast	Okla.	Beaver	2 21 62	Iss.
Cities Service Production Co.:					
G-11046 Tennessee Gas Transmission Co.	East Cameron Area.*	La.	Cameron & Vermilion.	1 22 62	Iss.
G-15330 Tennessee Gas Transmission Co.	East Cameron Area	La.	Cameron & Vermilion.	1 22 62	Iss.
Claiborne Gasoline Co.:					
CI60-221 Texas Eastern Transmission Corp.	Northeast Lisbon	La.	Claiborne	5 1 62	Iss.
E. B. Clark:					
CI61-1048 The Shamrock Oil & Gas Corp.	West Panhandle	Tex.	Moore	5 7 62	Iss.
N. G. Clark:					
G-20588 Equitable Gas Co.	Skin Creek District	W. Va.	Lewis	5 1 62	Iss.
CI61-765 Equitable Gas Co.	Skin Creek District	W. Va.	Lewis	5 1 62	Iss.
CI61-1812 Equitable Gas Co.	Court House District.	W. Va.	Lewis	5 1 62	Iss.
N. G. Clark, et al.:					
CI62-199 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
CI62-715 Equitable Gas Co.	Court House District.	W. Va.	Lewis	5 29 62	Iss.
Clark Oil Co.:					
CI62-674 Transwestern Pipeline Co.	Putnam	Tex.	Pecos	6 4 62	Iss.
Clayton Oil & Gas Co.:					
G-20166 Hope Natural Gas Co.	Union District	W. Va.	Clay	5 1 62	Iss.
Cleary Petroleum, Inc.:					
CI61-1226 Trunkline Gas Co.	Foxfield Area	Tex.	Bee	5 25 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Walter Clements, Jr., Operator, et al.:					
CI62-511 Cities Service Gas Co.	Palmer Unit	Kans.	Barber	5 29 62	Iss.
Charles E. Clowe, Jr., et al.:					
CI62-746 Lone Star Gas Co.	North Nellie	Okla.	Stephens	5 29 62	Iss.
Coastal Salvage Co., Inc.:					
CI61-1696 Natural Gas Pipeline Co. of America.	Fairbanks Area	Tex.	Harris	5 31 62	Iss.
Coastal States Gas Producing Co.:					
CI62-92 TranscontinentalGas Pipe Line Corp.	Mission Valley Area.	Tex.	Victoria	3 23 62	Iss.
Coastal States Gas Producing Co., et al.:					
CI60-46 Orange Grove Gas Gathering Co.	Orange Grove Area.	Tex.	Jim Wells	5 1 62	Iss.
Coastal States Gas Producing Co., Operator, et al.:					
G-20127 TennesseeGas Transmission Co.	Hidalgo	Tex.	Hidalgo	5 1 62	Iss.
CI60-421 United Gas Pipe Line Co.	North Laward	Tex.	Jackson	6 4 62	Iss.
Alton Coats, Operator, et al.:					
CI61-1381 Rio Sabine, Inc.	North Carthage	Tex.	Panola*	2 21 62	Iss.
J. L. Coats:					
CI62-680 Hope Natural Gas Co.	Salt Lake District	W. Va.	Braxton	5 29 62	Iss.
Coline Oil Corp.:					
CI62-379 Northern Natural Gas Co.	Hansford*	Tex.	Hansford	3 26 62	Iss.
Colorado Oil & Gas Corp.:					
CI62-52 Colorado Interstate Gas Co.	Southeast Griggs	Okla.	Cimarron	5 7 62	Iss.
Colorado Oil & Gas Corp., Operator, et al.:					
CI61-1545 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
Columbian Carbon Co.:					
CI62-498 Hope Natural Gas Co.	Sandy River District.	W. Va.	McDowell	4 17 62	Iss.
Columbian Fuel Corp.:					
CI61-1074 Cities Service Gas Co.	Guymon-Hugoton	Okla.	Texas	5 23 62	Iss.
CI61-1489 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Texas	1 8 62	Iss.
Bert T. Combs:					
CI61-1558 Kentucky West Virginia Gas Co.	Nunnery Branch of Johns Creek.	Ky.	Floyd	2 21 62	Iss.
CI62-659 Kentucky West Virginia Gas Co.	Lotts Creek	Ky.	Perry	5 29 62	Iss.
Commercial Solvents Corp.:					
G-17453 United Carbon Co.	Monroe	La.	Union	5 1 62	Iss.
Compadre Oil Corp., Operator, et al.:					
CI61-280 Lone Star Gas Co.	Nellie	Okla.	Stephens	5 7 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Compass Exploration Inc., Operator, et al.:					
CI61-1184 El Paso Natural Gas Co.	Undesignated	Colo.	La Plata	5 7 62	Iss.
CI62-579 El Paso Natural Gas Co.	Undesignated	N. Mex.	Rio Arriba	6 4 62	Iss.
CI62-598 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	6 4 62	Iss.
Louie A. Condry, Trustee:					
CI62-839 Hope Natural Gas Co.	West Union District.	W. Va.	Doddridge	6 4 62	Iss.
J. R. Cone:					
G-14503 Skelly Oil Co., et al.	Tubbs*	N. Mex.	Lea	6 18 62	Rej.
M. M. Conn:					
CI61-1673 Coastal Transmission Corp.	La Reforma	Tex.	Starr	5 25 62	Iss.
Consolidated Gas & Equipment Co. of America, Operator:					
CI61-1635 Natural Gas Pipeline Co. of America.	West Panhandle	Tex.	Carson	3 23 62	Iss.
Consolidated Oil & Gas Co., Inc.:					
CI62-64 Equitable Gas Co.	Central District	W. Va.	Doddridge	3 23 62	Iss.
Consolidated Oil & Gas, Inc.:					
CI61-762 El Paso Natural Gas Co.	Northwest Blanco	N. Mex.	San Juan	5 7 62	Iss.
CI62-748 El Paso Natural Gas Co.	Northwest Blanco-Mesa Verde.	N. Mex.	San Juan	5 7 62	Iss.
CI62-500 El Paso Natural Gas Co.	Basin Dakota	N. Mex.	San Juan	5 23 62	Iss.
CI62-1432 El Paso Natural Gas Co.	Basin-Dakota	N. Mex.	San Juan	6 18 62	Rej.
Consolidated Oil & Gas, Inc., Operator, et al.:					
G-17796 El Paso Natural Gas Co.	Blanco	N. Mex.	San Juan	5 25 62	Iss.
CI62-54 Kansas-Nebraska Natural Gas Co., Inc.	Cotton Valley	Colo.	Weld	2 21 62	Iss.
CI62-201 El Paso Natural Gas Co.	Northwest Blanco	N. Mex.	San Juan	3 26 62	Iss.
CI62-350 El Paso Natural Gas Co.	Blanco-Mesaverde*	N. Mex.	San Juan	4 17 62	Iss.
Continental Oil Co.:					
G-11204 Tennessee Gas Transmission Co.	West Cameron Area.*	La.	Cameron*	1 22 62	Iss.
G-11612 Cities Service Gas Co.	Rhodes	Kans.	Barber	3 26 62	Iss.
CI61-1238 Northern Natural Gas Co.	Hugoton	Kans.	Finney	1 8 62	Iss.
CI61-1810 El Paso Natural Gas Co.	Northeast Haynes	N. Mex.	Rio Arriba	3 23 62	Iss.
CI61-1811 El Paso Natural Gas Co.	Northeast Haynes	N. Mex.	Rio Arriba	3 23 62	Iss.
CI62-365 El Paso Natural Gas Co.	Lindrith Area	N. Mex.	Rio Arriba	5 29 62	Iss.
CI62-371 Panhandle Eastern Pipe Line Co.	Angell	Kans.	Meade	4 17 62	Iss.
CI62-464 Lone Star Gas Co.	Katie	Okla.	Garvin	5 31 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Continental Oil Co—Continued					
CI62-465 Wunderlich Development Co.	Undesignated	Okla	Kay	5 31 62	Iss.
CI62-466 Wunderlich Development Co.	Undesignated	Okla	Kay	5 31 62	Iss.
Continental Oil Co., Operator:					
CI61-1486 South Texas Natural Gas Gathering Co.	Lel Benadito	Tex	Starr	5 23 62	Iss.
Roy L. Cook:					
CI62-919 El Paso Natural Gas Co.	Aztec-Fruitland	N. Mex	San Juan	6 4 62	Iss.
William H. Cook, et al.:					
CI61-145 United Gas Pipe Line Co.	Cotton Valley	La	Webster	5 7 62	Iss.
W. J. Coppinger, Operator, et al.:					
G-15379 Cities Service Gas Co.	Hugoton	Kans	Finney	5 1 62	Iss.
Cosden Petroleum Corp.:					
CI62-175 Northern Natural Gas Co.	Hunt Baggett-Strawn.	Tex	Crockett	5 7 62	Iss.
Cosden Petroleum Corp., Operator, et al.:					
CI61-1652 Texas Eastern Transmission Corp.	Midway East	Tex	San Patricio	3 23 62	Iss.
Dale Cottrill:					
CI62-788 Hope Natural Gas Co.	Clay District	W. Va	Ritchie	5 29 62	Iss.
Edwin L. Cox:					
CI62-35 Panhandle Eastern Pipe Line Co.	Undesignated	Kans	Morton	3 23 62	Iss.
Edwin L. Cox, Operator, et al.:					
CI61-1235 Coastal States Gas Producing Co.	Garza Unit	Tex	Duval	5 23 62	Iss.
CI62- 67 Panhandle Eastern Pipe Line Co.	Undesignated	Kans	Seward	6 4 62	Iss.
John L. Cox:					
CI60-458 El Paso Natural Gas Co.	Benedum Spraberry	Tex	Upton	5 7 62	Iss.
Walter C. Crane, et al.:					
CI61-1514 Hope Natural Gas Co.	Union District	W. Va	Ritchie	5 29 62	Iss.
CI62-439 Hope Natural Gas Co.	Murphy District	W. Va	Ritchie	5 7 62	Iss.
John B. Crawford, Agent:					
CI62-10 Equitable Gas Co.	Troy District	W. Va	Gilmer	2 21 62	Iss.
Crawford Production Co.:					
CI61-1723 El Paso Natural Gas Co.	South Erie	Okla	Beckham	5 29 62	Iss.
Creek Oil Co., Inc., Operator, et al.:					
CI61-1729 Texas Gas Transmission Corp.	Graham Lake Area	Ky	Muhlenberg	5 29 62	Iss.
Crescent Drilling Co., Inc.:					
G-18453 Arkansas Louisiana Gas Co.	Ruston	La	Lincoln	5 1 62	Iss.
Creslenn Oil Co.:					
CI62-148 Texas Gas Transmission Corp.	Calhoun	La	Lincoln	3 23 62	Iss.
Crest Exploration Co.:					
G-19419 Wunderlich Development Co.	Bradbury	Kans	Cowley	5 29 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Crest Petrol Inc., Agent:					
G-19363 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
G-19366 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
G-19367 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
G-19368 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
G-19369 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
G-19371 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
G-19377 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
G-19378 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
Cricket Oil Co., Operator, et al.:					
CI61-896 Northern Natural Gas Co.	Hansford	Tex.	Hansford	6 4 62	Iss.
Emmett Cronin, Agent:					
CI62-678 Cabot Corp.	Murphy District	W. Va.	Ritchie	5 29 62	Iss
Dakin Oil Co.:					
CI62-751 North Central Gas Co.	Boone Doome Area	Wyo.	Natrona	5 23 62	Iss.
Virgil E. Daugherty:					
CI62-670 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	5 29 62	Iss.
Roger H. Davis:					
CI61-1587 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
William K. Davis:					
CI62-236 Trunkline Gas Co.	Southeast Alice	Tex.	Jim Wells	6 4 62	Iss.
William K. Davis, Operator, et al.:					
CI61-1313 Texas Eastern Transmission Corp.	S.E. Rhode Ranch	Tex.	McMullen	1 8 62	Iss.
Deb Oil & Gas Co.:					
GI18723 Equitable Gas Co.	Rosedale, Bert District.	W. Va.	Braxton	5 1 62	Iss.
C-61-1540 Equitable Gas Co.	Warren District	W. Va.	Upshur	2 21 62	Iss.
J. F. Deem, et. al.:					
CI62-484 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	4 17 62	Iss.
DeKalb Oil & Gas Co.:					
CI62-504 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	4 17 62	Iss.
A. R. Dillard, Operator, et al.:					
CI61-402 Northern Natural Gas Co.	Horizon	Tex.	Ochiltree	1 29 62	Iss.
Herbert L. Dillon, Jr.:					
CI62-194 Valley Gas Transmission, Inc.	South Pheasant	Tex.	Matagorda	5 23 62	Iss.
H.L. Dillon, Jr., et al.:					
CI62-677 Valley Gas Transmission, Inc.	Tsesmelis	Tex.	Jim Wells	5 23 62	Iss.
Roscoe Dingess, Jr., et al.:					
CI62-221 Hope Natural Gas Co.	Baileysville District.	W. Va.	Wyoming	3 26 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCERS, DOCKET NO. AND PURCHASERS	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Roscoe Dingess, Jr., et al.—Con.					
CI61-1298 Hope Natural Gas Co.	Clear Fork District	W. Va	Wyoming	1 29 62	Iss.
Dixilyn Drilling Corp., Operator:					
CI61-394 El Paso Natural Gas Co.	Jack Herbert	Tex	Upton	1 29 62	Iss.
James G. Dodd:					
CI62-44 Tennessee Gas Transmission Co.	North Aqua Dulce	Tex	Nueces	5 7 62	Iss.
Sam Y. Dorfman, Jr., et al.:					
CI61-1193 Texas Eastern Transmission Corp.	Willow Springs	Tex	Gregg	1 29 62	Iss.
Dorn & Miller Co.:					
CI62-385 Colorado Interstate Gas Co.	Patrick Draw Area	Wyo	Sweetwater	3 26 62	Iss.
D. A. Dorward:					
CI62-775 Hope Natural Gas Co.	Glenville District	W. Va	Gilmer	5 29 62	Iss.
D. A. Dorward, et al.:					
CI61-180 Hope Natural Gas Co.	Glenville District	W. Va	Gilmer	2 21 62	Iss.
CI62-863 Hope Natural Gas Co.	Sheridan District	W. Va	Calhoun	6 4 62	Iss.
Claude Drake, Jr.:					
CI62-56 United Fuel Gas Co.	Smithfield District	W. Va	Roane	6 4 62	Iss.
CI62-661 Hope Natural Gas Co.	Troy District	W. Va	Gilmer	5 29 62	Iss.
Claude Drake, Jr., et al.:					
CI61-1816 Hope Natural Gas Co.	DeKalb District	W. Va	Gilmer	2 21 62	Iss.
Paul V. Draughn, Sr.:					
CI61-85 United Gas Pipe Line Co.	Maxie & Pistol Ridge.	Miss	Forrest	1 8 62	Iss.
Dulaney Oil Co.:					
CI61-1355 Tennessee Gas Transmission Co.	El Puerto	Tex	Starr	1 8 62	Iss.
James R. Duncan, et al.:					
CI62-437 Hope Natural Gas Co.	Cove District	W. Va	Doddridge	3 26 62	Iss.
E. J. Dunigan, Jr.:					
CI62-409 El Paso Natural Gas Co.	South Erick	Okla	Beckham	5 7 62	Iss.
Stella Dysart:					
CI62-452 El Paso Natural Gas Co.	Basin Dakota	N. Mex	San Juan	5 23 62	Iss.
Eagle Oil Co.					
CI61-1457 United Fuel Gas Co.	Henry District	W. Va	Clay	5 1 62	Iss.
Ward M. Edinder, Inc.:					
G-18814 Jerrnigan & Morgan Transmission Co.	Undesignated	Okla	Lincoln	5 1 62	Iss.
Robert J. Edwards, Jr., et al.:					
CI62-200 Lone Star Gas Co.	Asphaltum	Okla	Jefferson	5 31 62	Iss.
John A. Egan, Operator, et al.:					
CI61-1175 El Paso Natural Gas Co.	San Juan	N. Mex	Rio Arriba	1 29 62	Iss.
John J. Eisner:					
CI61-1487 Northern Natural Gas Co.	Elmwood-Camp Creek.	Okla	Beaver	2 21 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
John J. Eisner, et al.:					
CI62-467 Northern Natural Gas Co.	Hansford Morrow	Tex.	Ochiltree	6 4 62	Iss.
John J. Eisner, Operator, et al.:					
CI62-450 Northern Natural Gas Co.	Hansford Morrow	Tex.	Ochiltree	5 29 62	Iss.
El Paso Natural Gas Products Co.:					
CI61-1461 Colorado Interstate Gas Co.	Patrick Draw Area.	Wyo.	Sweetwater	1 29 62	Iss.
Elkhurst Producing Co.:					
CI62-837 Hope Natural Gas Co.	Union District	W. Va.	Clay	6 4 62	Iss.
E. J. Elkins:					
CI62-383 South Penn Oil Co.	Washington District.	W. Va.	Boone	3 26 62	Iss.
James A. Elkins, Jr., et al.:					
CI62-436 Cities Service Gas Co.	Kansas-Hugoton	Kans.	Haskell	4 17 62	Iss.
Mark Elkins:					
CI62-290 El Paso Natural Gas Co.	Canyon Largo	N. Mex.	Rio Arriba	5 23 62	Iss.
Floyd E. Emrick, et al.:					
CI61-1715 Hope Natural Gas Co.	Spencer District	W. Va.	Roane	1 29 62	Iss.
A. R. Eppenauer, Operator:					
G-17383 El Paso Natural Gas Co.	Undesignated	N. Mex.	Lea	5 1 62	Iss.
Tell Evans Gas Co.:					
G-18895 Hope Natural Gas Co.	Lee District	W. Va.	Calhoun	3 26 62	Iss.
F. & I. Gas Co.:					
CI61-1716 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	1 29 62	Iss.
W. R. Fairchild & Associates, Inc.:					
G-20090 Tennessee Gas Transmission Co.	South Crowley	La.	Acadia	6 8 62	Dis.
Fairway Oil Co., Inc.:					
CI60-648 El Paso Natural Gas Co.	West Kutz	N. Mex.	San Juan	5 23 62	Iss.
Falcon Seaboard Drilling Co., et al.:					
CI62-208 Northern Natural Gas Co.	Harper Ranch Area	Kans.	Clark	5 29 62	Iss.
David Fasken, et al.:					
CI61-1228 Phillips Petroleum Co.	Azalea Devonian*	Tex.	Midland	6 4 62	Iss.
George D. Fehr:					
G-18544 El Paso Natural Gas Co.	Turner Bluff	Utah	San Juan	6 7 62	Wtd.
Harris R. Fender:					
CI61-1302 United Gas Pipe Line Co.	Tecula	Tex.	Cherokee	5 7 62	Iss.
Bill Ferguson:					
CI62-401 Panhandle Eastern Pipe Line Co.	Undesignated	Kans.	Meade	6 4 62	Iss.
Willard E. Ferrell, et al.:					
CI62-301 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	3 26 62	Iss.
Bert Fields:					
CI61-422 El Paso Natural Gas Co.	South Blanco	N. Mex.	Rio Arriba	1 29 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Richard M. Finder:					
CI61-121 Valley Gas Transmission, Inc.	Sejita	Tex	Duval	5 23 62	Iss.
CI61-1710 Valley Gas Transmission, Inc.	South Elsa	Tex	Hidalgo	5 23 62	Iss.
CI62-258 Valley Gas Transmission, Inc.	South Monte Christo.	Tex	Hidalgo	5 29 62	Iss.
Fireball Oil Co.:					
CI62-856 Hope Natural Gas Co.	Smithfield District	W. Va	Roane	6 4 62	Iss.
The First National Bank of Amarillo, Texas, Trustee:					
CI60-817 Colorado Interstate Gas Co.	West Panhandle Field.	Tex	Potter	1 8 62	Iss.
L. M. Fischer, Operator, et al.:					
CI61-934 Valley Gas Transmission, Inc.	Raminena	Tex	Live Oak	5 31 62	Iss.
CI62-205 Texas Eastern Transmission Corp.	South George West	Tex	Live Oak	5 29 62	Iss.
Durl Fluharty, et al.:					
CI61-1815 Equitable Gas Co.	Union District	W. Va	Ritchie	2 21 62	Iss.
CI62-849 Equitable Gas Co	Union District	W. Va	Ritchie	6 4 62	Iss.
James W. Fluharty Gas & Oil Co.:					
G-17088 Penova Interest	Calhoun Sheridan District.	W. Va	Calhoun	5 7 62	Iss.
Ralph T. Folwell, et al.:					
G-18245 Hope Natural Gas Co.	McKim District	W. Va	Pleasants	3 23 62	Iss.
William I. Forbes, Jr.:					
CI62-433 Equitable Gas Co	Meade District*	W. Va	Upshur*	5 29 62	Iss.
William Innes Forbes, Jr., et al.:					
CI62-18 Hope Natural Gas Co.	DeKalb District	W. Va	Gilmer	5 29 62	Iss.
Forest Oil Corp.:					
CI62-31 Colorado Interstate Gas Co.	Patrick Draw Area	Wyo	Sweetwater	1 29 62	Iss.
CI62-1413 Cimarron Transmission Co.	Undesignated	Okla	Love	6 8 62	Rej.
James M. Forgotson:					
CI62-352 Arkansas Louisiana Gas Co.	Vixen Field	La	Caldwell	4 17 62	Iss.
Forsythe Gas Conservation Co., Inc., Operator:					
CI61-786 Cities Service Gas Co.	Undesignated	Kans	Barber	5 25 62	Iss.
A. L. Forward & R. W. Yarborough:					
CI62-265 Valley Gas Transmission, Inc.	Orcones	Tex	Duval	5 23 62	Iss.
Grant G. Fowler, et al.:					
CI62-219 Equitable Gas Co	DeKalb District	W. Va	Gilmer	5 29 62	Iss.
James O. Fox, Jr., Operator, et al.:					
G-19414 West Texas Gathering Co.	Undesignated	Tex	Winkler	5 1 62	Iss.
John Franks, et al.:					
CI61-1199 Texas Gas Transmission Corp.	Calhoun	La	Lincoln	1 29 62	Iss.
CI62-394 United Gas Pipe Line Co.	Cotton Valley	La	Webster	3 26 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
The Frontier Refining Co.:					
CI61-1139 El Paso Natural Gas Co.	West Cutz Area	N. Mex.	San Juan	2 21 62	Iss.
CI62-414 El Paso Natural Gas Co.	Angels Peak Gallup Pool.	N. Mex.	San Jaun	4 17 62	Iss.
The Frontier Refining Co., Operator, et al.:					
CI61-1140 El Paso Natural Gas Co.	West Cutz Area	N. Mex.	San Juan	2 21 62	Iss.
Vernon W. Frost, et al.:					
G-19700 Texas Eastern Transmission Corp.	Cherokee Lake Area.	Tex.	Rusk	4 17 62	Iss.
Roy Furr, Operator, et al.:					
G-16293 Northern Natural Gas Co.	Undesignated	Tex.	Hansford	3 26 62	Iss.
Albert Gackle, Operator, et al.:					
G-10914 El Paso Natural Gas Co.	Jalmat	N. Mex.	Lea	6 4 62	Iss.
G-10915 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex.	Lea	6 4 62	Iss.
G-19016 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex.	Lea	6 4 62	Iss.
G-19017 El Paso Natural Gas Co.	Jalmat	N. Mex.	Lea	6 4 62	Iss.
D. L. Gainer, Agent:					
CI62-345 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	3 26 62	Iss.
J. F. Gainer Gas Co.:					
CI61-1517 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	3 26 62	Iss.
B. C. Garnett, Operator, et al.:					
CI61-1216 Coastal Transmission Corp.	Shield	Tex.	Nueces	5 7 62	Iss.
Edward Garvin Oil & Gas Co.:					
CI61-845 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 25 62	Iss.
Gas, Inc.:					
CI62-454 Panhandle Eastern Pipe Line Co.	Kansas-Hugoton*	Kans.	Seward*	4 17 62	Iss.
General American Oil Co. of Texas:					
G-16583 Northern Natural Gas Co.	McKinney	Kans.	Clark	5 25 62	Iss.
CI62-218 Arkansas Louisiana Gas Co.	West Marlow	Okla.	Stephens	5 23 62	Iss.
O. W. Gerwig, et. al.:					
CI62-836 Hope Natural Gas Co.	Center District	W. Va.	Gilmer	6 4 62	Iss.
Jean Paul Getty, Trustee:					
G-10342 Phillips Petroleum Co.	Guymon-Hugoton	Okla.	Texas	1 8 62	Iss.
Getty Oil Co.:					
CI61-1403 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex.	Lea	1 8 62	Iss.
H. M. Gillespie:					
G-13960 Kansas-Nebraska Natural Gas Co., Inc.	Hugoton	Kans.	Finney	3 26 62	Iss.
The Gilmer Oil Co.:					
CI62-354 Lone Star Gas Co.	Sholem Alechem	Okla.	Carter	4 17 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Gus Glasscock, Inc.:					
CI61-1372 Chelletex Corp.	Morales	Tex.	Jackson	1 8 62	Iss.
A. C. Glassell:					
CI61-1164 Arkansas Louisiana Gas Co.	Calhoun	La.	Ouachita	1 29 62	Iss.
Global Oils, Inc., Operator:					
CI62-1447 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	6 21 62	Rej.
Delbert Goff:					
CI62-302 Hope Natural Gas Co.	Hackers Creek District.	W. Va.	Lewis	5 29 62	Iss.
CI62-425 Hope Natural Gas Co.	Court House District.	W. Va.	Lewis	5 29 62	Iss.
CI62-543 Hope Natural Gas Co.	Center District	W. Va.	Gilmer	4 17 62	Iss.
Delbert Goff, et al.:					
CI61-1668 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	1 29 62	Iss.
CI62-648 Hope Natural Gas Co.	Salt Lick District	W. Va.	Braxton	5 29 62	Iss.
Estate of W. L. Goldston, et al.:					
G-18059 El Paso Natural Gas Co.	Spraberry Trend	Tex.	Glasscock	5 1 62	Iss.
W. J. Goldston, et al.:					
CI60-706 Coastal States Gas Producing Co.	East Mathis Area	Tex.	San Patricio	5 7 62	Iss.
Henry O. Gossett, Jr.:					
CI62-51 Equitable Gas Co.	Troy District*	W. Va.	Gilmer	2 21 62	Iss.
Henry O. Gossett, Jr., et al.:					
CI62-442 Equitable Gas Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
Graham-Michaelis Drilling Co.:					
G-16435 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Texas	3 26 62	Iss.
G-18956 Panhandle Eastern Pipe Line Co.	Forgan South Poor	Okla.	Beaver	5 1 62	Iss.
CI61-851 Northern Natural Gas Co.	McKinney	Kans.	Clark	5 25 62	Iss.
CI62-555 Northern Natural Gas Co.	Sitka Northeast*	Kans.	Clark	4 17 62	Iss.
Graham-Michaelis Drilling Co., Operator, et al.:					
CI61-2 Kansas-Nebraska Natural Gas Co., Inc.	Camrick Pool	Okla.	Texas	5 7 62	Iss.
William Graham Oil Co.:					
CI62-1 Kansas-Nebraska Gas Co., Inc.	Hugoton	Kans.	Finney	5 7 62	Iss.
Lloyd L. Gray:					
G-20263 Panhandle Eastern Pipe Line Co.	Iuka-Carmi	Kans.	Pratt	5 1 62	Iss.
CI60-417 Panhandle Eastern Pipe Line Co.	Will	Kans.	Edwards	5 7 62	Iss.
Great Western Drilling Co.:					
CI61-1693 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
James L. Greene, Jr., et al.:					
CI61-1051 El Paso Natural Gas Co.	Noelke	Tex.	Crockett	5 31 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER[2], DOCKET NO. AND PURCHASER[2]	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Jack W. Grigsby, Operator, et al.:					
G-19705 United Gas Pipe Line Co.	Undesignated	La.	Bienville	3 21 62	Iss.
CI62-881 United Gas Pipe Line Co.	Crescent Farms	La.	Terrebonne	5 29 62	Iss.
Gulf Oil Corp.:					
G-19162 Panhandle Eastern Pipe Line Co.	Camrick Pool	Okla.	Texas	3 26 62	Iss.
CI60-262 N. C. Ginther, Operator.	Bijou	Colo.	Morgan	5 29 62	Iss.
CI60-636 El Paso Natural Gas Co.	Red Wash	Utah	Uintah	6 11 62	Iss.
CI61-197 El Paso Natural Gas Co.	Ballard	N. Mex.	Rio Arriba	2 21 62	Iss.
CI61-665 Transwestern Pipeline Co.	Hokit	Tex.	Pecos	1 12 62	Wtd.
CI61-789 Lo-Vaca Gathering Co.	Rouch	Tex.	Goliad	5 12 62	Wtd.
CI61-820 Transwestern Pipeline Co.	White City Area	N. Mex.	Eddy	2 21 62	Iss
CI61-1213 Transwestern Pipeline Co.	Atoka	N. Mex.	Eddy	1 8 62	Iss.
CI61-1441 Lone Star Gas Co.	East Durant	Okla.	Bryan	5 23 62	Iss.
CI61-1544 Lone Star Gas Co.	Manziell	Tex.	Wood	1 8 62	Iss.
CI61-1555 Cities Service Gas Co.	Palmer	Kans.	Barber	2 21 62	Iss.
CI61-1691 Coastal States Gas Producing Co.	East Mathis	Tex.	San Patricio	5 23 62	Iss.
CI61-1711 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
CI62-47 Colorado Interstate Gas Co.	Patrick Draw Area	Wyo.	Sweetwater	1 29 62	Iss.
CI62-166 El Paso Natural Gas Co.[3]	King Mountain	Tex.	Upton	5 29 62	Iss.
CI62-322 Cities Service Gas Co.	Northeast Waynoka	Okla.	Woods	5 29 62	Iss.
CI62-469 Arkansas Louisiana Gas Co.	South Marlow	Okla.	Stephens	4 17 62	Iss.
Gulf Oil Corp., Operator, et al.:					
CI61-449 Kansas-Nebraska Natural Gas Co., Inc.	Sterling	Colo.	Logan	5 7 62	Iss.
Ralph C. Halbert, Operator, et al.:					
CI62-207 United Fuel Gas Co.	Elk District[3]	W. Va.	Kanawha	6 4 62	Iss.
Victor Hale, et al.:					
CI62-482 Columbian Fuel Corp.	Middle Creek	Ky.	Floyd	6 4 62	Iss.
C. E. Hall:					
CI62-669 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 29 62	Iss.
M. A. Hall:					
CI60-651 The Ohio Fuel Gas Co.	Undesignated	Ohio	Meigs	4 17 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCERS, DOCKET NO. AND PURCHASERS	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Frederick C. and Ferris F. Hamilton:					
CI61-1458 Kansas-Nebraska Natural Gas Co., Inc.	Camrick	Okla.	Texas	2 21 62	Iss.
CI62-45 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Texas	3 23 62	Iss.
CI62-267 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Texas	5 29 62	Iss.
Jake L. Hamon:					
G-17617 El Paso Natural Gas Co.	University Lands	Tex.	Andrews	3 26 62	Iss.
G-20594 Michigan Wisconsin Pipe Line Co.	Laverne	Okla.	Harper	4 17 62	Iss.
CI61-662 Coastal States Gas Producing Co.	Poesta Creek	Tex.	Bee	5 23 62	Iss.
Jake L. Hamon, Operator, et al.:					
CI62-536 United Gas Pipe Line Co.	Choate Creek Area	Tex.	Karnes	4 17 62	Iss.
James D. Hancock and James D. Hancock, Jr.:					
G-15160 El Paso Natural Gas Co.	Undesignated	N. Mex.	Rio Arriba	5 25 62	Iss.
Hanley Co.:					
G-10096 El Paso Natural Gas Co.	Spraberry Trend	Tex.	Glasscock	3 26 62	Iss.
Hanley Co., Operator:					
G-10879 El Paso Natural Gas Co.	H. S. Gray Lease	Tex.	Glasscock	1 8 62	Iss.
Estate of M. G. Hansbro, Deceased:					
CI62-37 United Gas Pipe Line Co.	Bethany	Tex.	Panola	5 29 62	Iss.
Jack Harden, Operator, et al.:					
CI62-13 Cities Service Gas Co.	Southeast Wimer	Okla.	Nowata	3 23 62	Iss.
Don W. Hardman:					
CI61-791 Hope Natural Gas Co.	Spruce Creek, Union District.	W. Va.	Ritchie	5 7 62	Iss.
CI62-253 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 29 62	Iss.
CI62-645 Hope Natural Gas Co.	Leatherbark, Murray District.	W. Va.	Ritchie	5 29 62	Iss.
CI62-829 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	6 4 62	Iss.
Don W. Hardman, et al.:					
CI61-1592 Hope Natural Gas Co.	Troy District	W. Va.	Gilmer	1 8 62	Iss.
CI61-1594 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	1 8 62	Iss.
CI61-1765 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	2 21 62	Iss.
Ira S. Hardman, Jr.:					
CI62-506 Hope Natural Gas Co.	Hackers Creek District.	W. Va.	Lewis	6 4 62	Iss.
Harkins & Co., Operator, et al.:					
CI61-1320 United Gas Pipe Line Co.	Albrecht	Tex.	Goliad	1 29 62	Iss.
David J. Harmer:					
CI61-49 Equitable Gas Co.	Freemans Creek District.	W. Va.	Lewis	1 8 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Harper Oil Co.:					
CI62-173 Panhandle Eastern Pipe Line Co.	Forgan	Okla	Beaver	3 23 62	Iss.
Harper Oil Co., Operator:					
CI62-1447 El Paso Natural Gas Co.	Undesignated	Okla	Beckham	1 8 62	Iss.
Harrell Drilling Co.:					
G-11645 Coastal States Gas Producing Co.	Hidalgo	Tex	Hidalgo	3 26 62	Iss.
G-14388 Coastal States Gas Producing Co.	Hidalgo	Tex	Hidalgo	5 1 62	Iss.
Harrell Drilling Co., et al.:					
G-14389 Coastal States Gas Producing Co.	Hidalgo	Tex	Hidalgo	5 1 62	Iss.
G-14390 Coastal States Gas Producing Co.	North Donna	Tex	Hidalgo	5 1 62	Iss.
G-14391 Coastal States Gas Producing Co.	Los Torritos	Tex	Hidalgo	5 1 62	Iss.
G-14392 Coastal States Gas Producing Co.	North Donna	Tex	Hidalgo	5 1 62	Iss.
G-14393 Coastal States Gas Producing Co.	Los Torritos	Tex	Hidalgo	5 1 62	Iss.
G-14942 Coastal States Gas Producing Co.	North Donna	Tex	Hidalgo	5 1 62	Iss.
G-14952 Coastal States Gas Producing Co.	North Donna	Tex	Hidalgo	3 26 62	Iss.
G-16738 Coastal States Gas Producing Co.	Hidalgo	Tex	Hidalgo	3 26 62	Iss.
D. D. Harrington:					
CI61-1303 Northern Natural Gas Co.	Hugoton	Tex	Stevens	3 23 62	Iss.
Harris & Spurgeon Gas Co.:					
CI62-266 South Penn Oil Co.	Troy District	W. Va.	Gilmer	5 29 62	Iss.
Dewey Harris, et al.:					
G-14161 Equitable Gas Co.	Skin Creek District	W. Va.	Lewis	5 1 62	Iss.
J. E. Harris, et al.:					
CI61-1607 Columbian Fuel Corp.	Middle Creek District.	Ky.	Floyd	5 23 62	Iss.
Blaine Hart, et al.:					
CI62-838 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	6 4 62	Iss.
E. C. Hartman, et al.:					
CI61-867 Equitable Gas Co.	Murphy District	W. Va.	Ritchie	5 7 62	Iss.
Edward M. Hartman:					
CI62-637 El Paso Natural Gas Co.	Bloomfield Area	N. Mex.	San Juan	5 29 62	Iss.
W. L. Hartman:					
CI61-1360 Cities Service Gas Co.	Hugoton	Kans.	Finney	5 23 62	Iss.
Harvey Gas Co.:					
CI61-430 Hope Natural Gas Co.	Clear Fork District	W. Va.	Wyoming	1 29 62	Iss.
Glenn L. Haught:					
CI62-161 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 29 62	Iss.
Glenn L. Haught, et al.:					
CI62-667 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 29 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
K. C. Hawkinson, et al.:					
CI61-1667 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
Ernest Hayhurst, et al.:					
CI61-1784 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	5 29 62	Iss.
Haynes & V. T. Drilling Co., Operator:					
G-16768 El Paso Natural Gas Co.	Jalmat	N. Mex.	Lea	5 1 62	Iss.
Charles A. Haynes, Operator, et al.:					
CI61-1536 Transwestern Pipeline Co.	Mesa Vista McKee	Tex.	Pecos	2 21 62	Iss.
CI62-518 El Paso Natural Gas Co.	South Santa Rosa Devonian Gas.	Tex.	Pecos	6 4 62	Iss.
Hays and Co., Agent:					
G-13247 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	3 23 62	Iss.
CI60-196 Hope Natural Gas Co.	Lee District	W. Va.	Calhoun	5 29 62	Iss.
CI62-180 Hope Natural Gas Co.	Lee District	W. Va.	Calhoun	5 29 62	Iss.
Hays & Co., Agent:					
CI62-426 Hope Natural Gas Co.	Lee District	W. Va.	Calhoun	5 7 62	Iss.
CI62-866 Hope Natural Gas Co.	Court House District.	W. Va.	Lewis	6 4 62	Iss.
Paul Heaster:					
CI62-226 Equitable Gas Co.	West Union District	W. Va.	Doddridge	3 26 62	Iss.
G. F. Hedges, Jr., et al.:					
CI62-854 Hope Natural Gas Co.	Troy District	W. Va.	Gilmer	6 4 62	Iss.
W. L. Heeter, et al.:					
CI62-87 United Fuel Gas Co.	Smithville District	W. Va.	Roane	3 23 62	Iss.
The Hefner Co., Operator, et al.:					
CI62-268 Lone Star Gas Co.	Fox-Graham*	Okla.	Carter*	3 26 62	Iss.
W. J. Hefner:					
CI61-576 Cities Service Gas Co.	Northeast Florence	Okla.	Grant	5 7 62	Iss.
Roy Heidelberg, II:					
CI61-414 Arkansas Louisiana Gas Co.	Calhoun	La.	Ouachita	1 29 62	Iss.
Thomas K. Hendrick, et al.:					
CI61-782 Panhandle Eastern Pipe Line Co.	Topeka-Greenwood	Okla.	Texas	4 17 62	Iss.
CI61-863 Panhandle Eastern Pipe Line Co.	Topeka-Greenwood	Okla.	Texas	4 17 62	Iss.
Thomas K. Hendrick, Operator, et al.:					
CI61-1161 Panhandle Eastern Pipe Line Co.	Topeka-Greenwood	Okla.	Texas	4 17 62	Iss.
CI62-481 Panhandle Eastern Pipe Line Co.	Topeka-Greenwood	Okla.	Texas	4 17 62	Iss.
George Hepfl:					
CI61-451 United Natural Gas Co.	Highland Township	Pa.	Carlton	5 7 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Herd Oil & Gas Co.:					
G-15446 El Paso Natural Gas Co.	Denton	N. Mex.	Lea	5 25 62	Iss.
Highland Oil Co.:					
CI61-1149 Texas Eastern Transmission Corp.	North Donna Area	Tex.	Hidalgo	1 29 62	Iss.
Roy G. Hildreth:					
CI62-797 Hope Natural Gas Co.	Spencer District	W. Va.	Roane	6 4 62	Iss.
Roy G. Hildreth, et al.:					
CI62-222 Equitable Gas Co.	DeKalb District	W. Va.	Gilmer	3 26 62	Iss.
A. G. Hill:					
CI62-252 Equitable Gas Co.	Court House District.	W. Va.	Lewis	6 4 62	Iss.
A. G. Hill, et al.:					
CI62-5 Texas Eastern Transmission Corp.	Mercedes	Tex.	Hidalgo	3 23 62	Iss.
J. E. Hillier, Operator, et al.:					
CI61-517 Syljo Gas Co.	Maetze	Tex.	Goliad	5 23 62	Iss.
E. C. Hitchcock, et al.:					
CI61-1154 El Paso Natural Gas Co.	Tex-Mex	Tex.	Gaines	5 1 62	Iss.
T. F. Hodge, Operator, et al.:					
CI61-875 Equitable Gas Co.	Murphy	W. Va.	Ritchie	5 7 62	Iss.
CI62-733 Texas Eastern Gas Transmission Corp.	South Karon	Tex.	Live Oak*	5 29 62	Iss.
CI62-793 Texas Eastern Transmission Corp.	Rudman	Tex.	Bee	5 29 62	Iss.
Robert L. Holland, et al.:					
CI62-183 Hope Natural Gas Co.	New Milton District.	W. Va.	Doddridge	5 29 62	Iss.
Ronald L. Hooser:					
CI62-558 United Fuel Gas Co.	Grant District	W. Va.	Wayne	6 4 62	Iss.
Alvin C. Hope, Operator:					
CI61-1672 West Lake Natural Gasoline Co.	Lake Trammell	Tex.	Nolan	5 23 62	Iss.
Hopeful Oil & Gas Co.:					
CI61-1619 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	1 29 62	Iss.
L. B. Horn:					
CI61-476 Coastal States Gas Producing Co.	A & H Field Area	Tex.	Duval	5 23 62	Iss.
L. B. Horn, Operator, et al.:					
CI62-391 Coastal States Gas Producing Co.	East Fitzsimmons	Tex.	Duval	5 23 62	Iss.
Benjamin K. Horton, et al.:					
CI62-29 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	2 21 62	Iss.
I. C. Houck:					
CI62-666 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 29 62	Iss.
I. C. Houck, et al.:					
CI62-299 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	3 26 62	Iss.
J. M. Huber Corp.:					
CI61-644 Colorado Interstate Gas Co.	Panhandle	Tex.	Hutchinson	6 1 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
J. M. Huber Corp.—Continued					
CI62-1146 Michigan Wisconsin Pipe Line Co.	Woodward	Okla.	Major*	3 7 62	Iss.
CI61-1329 Northern Natural Gas Co.	Snake Creek	Kans.	Clark	1 8 62	Iss.
CI62-552 Panhandle Eastern Pipe Line Co.	Northwest Carthage Area.	Okla.	Texas	4 17 62	Iss.
W. H. Hudson:					
CI61-1806 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	1 29 62	Iss.
Humble Oil & Refining Co.:					
G-15893 Arkansas Louisiana Gas Co.	Colquitt	La.	Claiborne	5 1 62	Iss.
G-15900 Northern Natural Gas Co.	N.W. Dower Field	Okla.	Beaver	1 8 62	Iss.
G-17046 Lone Star Gas Co.	Katie	Okla.	Garvin	5 7 62	Iss.
G-18882 Natural Gas Pipeline Co. of America.	Camrick	Okla.	Beaver	5 1 62	Iss.
G-19515 Natural Gas Pipeline Co. of America.	Camrick S.E. Pool	Tex.	Beaver	5 29 62	Iss.
CI60-65 El Paso Natural Gas Co.	Tip Top-Hogsback	Wyo.	Sublette*	6 11 62	Iss.
CI60-66 El Paso Natural Gas Co.	Tip Top-Hogsback	Wyo.	Sublette*	6 11 62	Iss.
CI61-689 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Texas	1 8 62	Iss.
CI61-697 Panhandle Eastern Pipe Line Co.	Undesignated	Tex.	Hansford	1 8 62	Iss.
CI61-1099 United Gas Pipe Line Co.	North Jacksonville	Tex.	Cherokee	5 7 62	Iss.
CI61-1177 Arkansas Louisiana Gas Co.	Cheniere Creek	La.	Ouachita	1 29 62	Iss.
CI61-1296 South Texas Natural Gas Gathering Co.	Chihuahua	Tex.	Hidalgo	5 23 62	Iss.
CI61-1306 Trunkline Gas Co.	Heard Ranch and Medio Creek.	Tex.	Bee	1 8 62	Iss.
CI61-1360 United Gas Pipe Line Co.	Normanna	Tex.	Bee	1 8 62	Iss.
CI61-1677 Transcontinental Gas Pipe Line Corp.	Cooke	Tex.	La Salle	1 8 62	Iss.
CI61-1982 United Gas Pipe Line Co.	Mt. Selman	Tex.	Cherokee	3 23 62	Iss.
CI62-243 Arkansas Louisiana Gas Co.	Beaver N.W. Pool	Okla.	Grady	3 26 62	Iss.
CI62-566 Northern Natural Gas Co.	Camrick	Okla.	Beaver	4 17 62	Iss.
Glen Humphery, Jr.:					
G-16773 Transcontinental Gas Pipe Line Corp.	Mission Valley	Tex.	Victoria	5 1 62	Iss.
Hassie Hunt Trust:					
G-16763 United Gas Pipe Line Co.	Bryceland Area	La.	Bienville	3 21 62	Iss.
Lyda Hunt—Bunker Trusts:					
CI62-1326 El Paso Natural Gas Co.	Brown-Bassett Field.	Tex.	Terrell	6 4 62	Rej.
Lyda Hunt—Caroline Trusts:					
CI62-1329 El Paso Natural Gas Co.	Brown-Bassett	Tex.	Terrell	6 4 62	Rej.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Lyda Hunt—Herbert Trusts:					
CI62-1325 El Paso Natural Gas Co.	Brown-Bassett	Tex.	Terrell	4 4 62	Rej.
Lyda Hunt—Lamar Trusts:					
CI62-1329 El Paso Natural Gas Co.	Brown-Bassett	Tex.	Terrell	6 4 62	Rej.
Lyda Hunt—Margaret Trusts:					
CI62-1324 El Paso Natural Gas Co.	Brown-Bassett	Tex.	Terrell	6 4 62	Rej.
Hunt Oil Co.:					
G-16737 United Gas Pipe Line Co.	Ada Area	La.	Bienville	3 21 62	Iss.
G-18260 El Paso Natural Gas Co.	Wemac	Tex.	Andrews	3 23 62	Iss.
CI62-104 Texas Gas Transmission Corp.	Mindon	La.	Webster	5 29 62	Iss.
W. H. Hunt:					
CI61-1568 South Texas Natural Gas Gathering Co.	El Benadito	Tex.	Starr	5 23 62	Iss.
R. J. Hunter, et al.:					
CI62-708 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
Husky Oil Co., Operator, et al.:					
CI61-186 Montana Dakota Utilities Co.	Manderson-Slick Area.	Wyo.	Big Horn	5 23 62	Iss.
Imperial Oil Co., et al.:					
CI62-473 South Penn Oil Co.	McElroy District	W. Va.	Tyler	4 17 62	Iss.
Inco 3, Inc.:					
CI61-928 Equitable Gas Co.	West Union District	W. Va.	Doddridge	1 29 62	Iss.
CI62-75 Manufacturers Light & Heat Co.	McElroy District	W. Va.	Tyler	3 23 62	Iss.
Indeco Corp.:					
CI61-1590 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
Henry S. Inger:					
G-19148 Wunderlich Development Co.	Hobaugh Lease	Okla.	Kay	3 26 62	Iss.
Jackson & Bowers:					
CI62-770 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	5 29 62	Iss.
Jackson & Yaste Oil & Gas Co.:					
CI62-716 Hope Natural Gas Co.	Grant District	W. Va.	Ritchie	5 29 62	Iss.
George Jackson:					
CI61-1410 Equitable Gas Co.	DeKalb District	W. Va.	Gilmer	1 29 62	Iss.
CI62-238 Hope Natural Gas Co.	Union District*	W. Va.	Preston	5 29 62	Iss.
L. B. Jackson Co., Operator, et al.:					
CI61-1792 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
The Jade Oil Co., et al.:					
CI62-172 United Gas Pipe Line Co.	Heinze	Tex.	Harris	5 31 62	Iss.
Jalou Gas Co.:					
CI62-88 El Paso Natural Gas Co.	Sha Sha*	N. Mex.	San Juan	3 23 62	Iss

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
James Drilling Corp., et al.:					
CI61-1768 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	2 21 62	Iss.
T. L. James & Co., Inc.:					
G-14854 Arkansas Louisiana Gas Co.	North Ruston	La.	Lincoln	6 4 62	Iss.
G-19408 United Gas Pipe Line Co.	Calhoun Area	La.	Ouachita	3 21 62	Iss.
Stanley R. Jaynes, et al.:					
CI62-878 Hope Natural Gas Co.	Court House District.	W. Va.	Lewis	6 4 62	Iss.
Johnson & French Oil Co.:					
CI61-1610 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex.	Lea	5 23 62	Iss.
CI61-1680 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex.	Lea	6 4 62	Iss.
Mosey Johnson & George W. Hall:					
CI62-875 United Fuel Gas Co.	Undesignated	Ky.	Pike	6 4 62	Iss.
G. C. Jones, et al.:					
CI61-1359 Equitable Gas Co.	Clay District	W. Va.	Ritchie	1 8 62	Iss.
J. E. Jones:					
CI61-1399 El Paso Natural Gas Co.	Clear Fork	Tex.	Upton	5 1 62	Iss.
Lenoir M. Josey, Inc., Operator:					
CI62-509 United Gas Pipe Line Co.	Blanconia	Tex.	Bee	5 1 62	Iss.
Kamp Enterprises:					
CI60-433 El Paso Natural Gas Co.	Gavilan Pictured Cliffs.	N. Mex.	Rio Arriba	5 7 62	Iss.
Kansas Natural Gas., Inc.:					
CI62-95 Phillips Petroleum Co.	Undesignated	Tex.	Sherman	2 21 62	Iss.
Katz Oil Co., et al.:					
CI60-464 Coastal States Gas Producing Co., et al.	Johns	Tex.	Duval	1 8 62	Iss.
Emby Kaye, et al.:					
CI61-1654 Oklahoma Natural Gas Gathering Corp, et al.	Ringwood	Okla.	Major	3 30 62	Iss.
A. A. Kelley:					
CI62-700 Barron Kidd	Clay District	W. Va.	Ritchie	5 29 62	Iss.
Kenwood Oil Co.:					
CI61-958 El Paso Natural Gas Co.	Jal	N. Mex.	Lea	5 7 62	Iss.
Kerr-McGee Oil Industries, Inc.:					
CI61-81 Northern Natural Gas Co.	John Creek	Tex.	Hutchinson	1 8 62	Iss.
CI61-785 Michigan Wisconsin Pipe Line Co.	Woodward Area	Okla.	Woodward*	3 7 62	Iss.
CI62-57 Panhandle Eastern Pipe Line Co.	Mocane	Okla.	Beaver	3 23 62	Iss.
Kewanee Oil Co., Operator, et al.:					
CI61-1473 Gas Transport, Inc.	Tygart District	W. Va.	Wood	3 23 62	Iss.
Kimbark Exploration Co., Operator, et al.:					
CI61-1651 Kansas - Nebraska Natural Gas Co., Inc.	Elm Grove	Colo.	Logan	1 8 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Kay Kimbell, Operator, et al.:					
CI60-715 El Paso Natural Gas Co.	Undesignated	N. Mex.	Rio Arriba	1 17 62	Iss.
Kay Kimble Oil Properties, Operator:					
CI61-154 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	2 21 62	Iss.
CI61-695 El Paso Natural Gas Co.	San Juan Basin	N. Mex.	San Juan	5 7 62	Iss.
Kay Kimble Oil Properties, Operator, et al.:					
CI61-138 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	2 21 62	Iss
CI61-1334 El Paso Natural Gas Co.	Undesignated	N. Mex.	Rio Arriba	5 23 62	Iss.
CI62-39 El Paso Natural Gas Co.	Undesignated	N. Mex.	Rio Arriba	3 23 62	Iss.
Kincaid Oil & Gas Co.:					
CI61-1415 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	1 8 62	Iss.
CI62-288 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	3 26 62	Iss.
CI62-646 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 29 62	Iss.
King-Stevenson Oil Co., Inc.:					
CI61-813 Panhandle Eastern Pipe Line Co.	Northeast Selling	Okla.	Dewey*	1 15 62	Iss.
C. L. Kingsbury, et al.:					
CI61-1575 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	1 8 62	Iss.
CI62-493 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	4 17 62	Iss.
Kingwood Oil Co., et al.:					
CI61-1628 Cities Service Gas Co.	Undesignated	Okla.	Comanche	3 23 62	Iss.
CI62-139 Natural Gas Pipeline Co. of America.	Boyd Field	Okla.	Beaver	5 29 62	Iss.
Lee Kinnebrew Jr., et al.:					
CI61-1347 El Paso Natural Gas Co.	East Panhandle Field.	Tex.	Gray	1 8 62	Iss.
Norman V. Kinsey, Jr., et al.:					
G-16278 United Gas Pipe Line Co.	Bryceland Area	La.	Bienville	3 21 62	Iss.
Kirby Petroleum Co., Operator, et al.:					
CI62-184 United Gas Pipe Line Co.	Betty Keenan	Tex.	Victoria	5 29 62	Iss.
Kirby Production Co., Operator, et al.:					
CI61-1160 United Gas Pipe Line Co.	Jacksonville	Tex.	Cherokee	1 29 62	Iss.
R. L. Kirkwood:					
CI62-260 Banquete Gas Co.	Spartan & Odem	Tex.	San Patricio	5 29 62	Iss.
Burt Kleiner, as Agent and Attorney in Fact:					
CI61-634 Lo-Vaca Gathering Co.	Magnolia Beach	Tex.	Calhoun	3 3 62	Wtd.
Fred C. Koch:					
CI62-861 El Paso Natural Gas Co.	Bloomfield Area	N. Mex.	San Juan	5 23 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Charles F. Koontz:					
CI62-210 Hope Natural Gas Co.	Troy District	W. Va.	Gilmer	5 29 62	Iss.
Krebs Associates:					
CI62-142 Hope Natural Gas Co.	Skin Creek District.	W. Va.	Lewis	5 29 62	Iss.
J. P. Krenitsky, et al.:					
G-19379 Gas Transport Inc.	Ravenswood District.	W. Va.	Jackson	4 17 62	Iss.
Lab Oil Co.:					
CI60-374 Orange Grove Gas Gathering Co.	Wade City	Tex.	Jim Wells	5 1 62	Iss.
Lab Oil Co., Operator, et al.:					
CI61-1148 Altex Corp.	West Alice	Tex.	Jim Wells	5 23 62	Iss.
Laffoon Oil Co.:					
CI60-613 Jernigan & Morgan Transmission Co.	North Wellston	Okla.	Lincoln	5 7 62	Iss.
La Gloria Oil & Gas Co., et al.:					
CI61-80 Texas Eastern Transmission Corp.	Sugar Creek Field	La.	Claiborne	1 8 62	Iss.
Lario Oil & Gas Co.:					
CI62-520 Colorado Interstate Gas Co.	Hugoton	Kans.	Seward	4 17 62	Iss.
David Law:					
CI61-1231 Equitable Gas Co.	Freemans Creek District.	W. Va.	Lewis	1 8 62	Iss.
David W. Law, et al.:					
CI61-410 Equitable Gas Co.	West Union District.	W. Va.	Doddridge	1 29 62	Iss.
CI61-1814 Equitable Gas Co.	Freemansburg District.	W. Va.	Lewis	1 29 62	Iss.
Lawson Petroleum Co., Operator, et al.:					
CI61-1623 Northern Natural Gas Co.	Hugoton	Kans.	Finney	1 8 62	Iss.
Donald G. Lazzelle, Jr., Agent:					
CI61-1365 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	1 29 62	Iss.
Lazy-2, Inc.:					
CI62-562 South Penn Oil Co.#	Scott District	Ky.	Boone	5 23 62	Iss.
R. E. Lee:					
G-18525 Northern Natural Gas Co.	Hansford	Tex.	Hansford	3 26 62	Iss.
Jack R. Lefever, et al.:					
CI62-211 Equitable Gas Co.	Greenwood, Central District.	W. Va.	Doddridge	5 29 62	Iss.
Philip Lemon, et al.:					
CI61-443 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	1 29 62	Iss.
Philip Lemon, et al.:					
CI61-1200 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	1 29 62	Iss.
CI62-665 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 29 62	Iss.
J. M. Leonard:					
CI60-527 El Paso Natural Gas Co.	Spraberry Trend	Tex.	Reagan	5 1 62	Iss.
Edward B. Leslie, Trustee:					
CI62-306 Kentucky West Virginia Gas Co.	Johns Creek	Ky.	Floyd	5 23 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Liberty Fuel Corp.:					
CI62-410 Hope Natural Gas Co.	Salt Lick District	W. Va.	Braxton	5 31 62	Iss.
Forrest H. Lindsay:					
CI61-1553 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
H. B. Lively, Operator, et al.:					
CI61-614 Coastal States Gas Producing Co.	Linke	Tex.	Bee	5 23 62	Iss.
CI61-624 Coastal States Gas Producing Co.	South Yougeen	Tex.	Bee	5 23 62	Iss.
Livingston Oil Co., Operator:					
CI61-1557 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
London Gas Co., Operator, et al.:					
G-17476 Lone Star Gas Co.	Asphaltum	Okla.	Jefferson	5 1 62	Iss.
C. E. Long, et al.:					
CI62-374 El Paso Natural Gas Co.	South Eunice	N. Mex.	Lea	4 17 62	Iss.
George Longfellow:					
CI62-786 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	5 29 62	Iss.
Luray Land, Inc.:					
CI60-1717 Hope Natural Gas Co.	Court House District.	W. Va.	Lewis	5 29 62	Iss.
CI61-96 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	1 8 62	Iss.
CI61-1786 Hope Natural Gas Co.	Court House District.	W. Va.	Lewis	3 23 62	Iss.
CI62-515 Hope Natural Gas Co.	Clark District	W. Va.	Harrison	6 4 62	Iss.
CI62-668 Hope Natural Gas Co.	Clark District	W. Va.	Harrison	5 29 62	Iss.
CI62-791 Hope Natural Gas Co.	Union District	W. Va.	Harrison	5 29 62	Iss.
C. H. Lyons, Jr., et al.:					
CI61-1001 Transwestern Pipeline Co.	Elmwood West	Okla.	Beaver	2 21 62	Iss.
C. H. Lyons, Sr., et al.:					
G-18642 Arkansas Louisiana Gas Co.	Colquitt	La.	Claiborne	5 1 62	Iss.
MPS Production Co., Operator, et al.:					
CI61-70 Tennessee Gas Transmission Co.	Sugar Valley	Tex.	Matagorda	1 8 62	Iss.
MWJ Producing Co., Operator, et al.:					
G-18491 El Paso Natural Gas Co.	Spraberry Trend Area.	Tex.	Reagan	3 26 62	Iss.
K. E. McAfee:					
CI62-254 El Paso Natural Gas Co.	Basin	N. Mex.	San Juan	5 29 62	Iss.
Paul L. McBride, Jr.:					
G-18915 United Gas Pipe Line Co.	North Henderson	Tex.	Rusk	4 9 62	Wtd.
W. C. McBride, Inc.:					
CI62-602 Arkansas Louisiana Gas Co.	South Marlow	Okla.	Stephens	4 17 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
W. C. McBride, Inc., Operator, et al.:					
CI61-1707 Panhandle Eastern Pipe Line Co.	Northwest Eva Area.	Okla.	Texas	3 23 62	Iss.
CI62-318 Cities Service Gas Co.	Garden City East Area.	Kans.	Finney	5 29 62	Iss.
McCall Drilling Co., Inc.:					
CI62-151 Equitable Gas Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
CI62-534 Hope Natural Gas Co.	Troy District	W. Va.	Gilmer	4 17 62	Iss.
William E. McCommons:					
CI62-496 United Gas Pipe Line Co.	Baxterville	Miss.	Lamar	3 26 62	Iss.
McCormick and Short, Operator, et al.:					
CI62-541 Natural Gas Pipeline Co. of America.	Urbana Yegua	Tex.	San Jancinto	4 17 62	Iss.
Alma McCutchin, et al.:					
CI61-1813 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
R. E. McDowell:					
CI62-361 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	3 26 62	Iss.
CI62-460 Equitable Gas Co.	Leading Creek	W. Va.	Gilmer	5 7 62	Iss.
T. H. McElvain:					
CI61-1674 El Paso Natural Gas Co.	Ignacio Blanco	Colo.	La Plata	1 8 62	Iss.
CI62-650 El Paso Natural Gas Co.	Ignacio Blanco	Colo.	La Plata	5 29 62	Iss.
CI62-882 El Paso Natural Gas Co.	Ignacio Blanco	Colo.	La Plata	6 4 62	Iss.
T. H. McElvain, et al.:					
G-17811 El Paso Natural Gas Co.	Blanco	N. Mex.	Rio Arriba*	5 23 62	Iss.
T. H. McElvain, Operator, et al.:					
CI62-446 El Paso Natural Gas Co.	Blanco	Colo.	La Plata	4 17 62	Iss.
Horace F. McKay, Jr.:					
CI62-49 El Paso Natural Gas Co.	Basin Dakota	N. Mex.	San Juan	6 4 62	Iss.
Horace F. McKay, Jr., Operator, et. al.:					
G-16777 El Paso Natural Gas Co.	San Juan Basin	N. Mex.	San Juan	3 26 62	Iss.
W. L. McKnight:					
CI62-647 Northern Natural Gas Co.	Undesignated	Tex.	Ochiltree	5 29 62	Iss.
Alfred E. McLane Estate:					
CI62-609 El Paso Natural Gas Co.	Bloomfield Area	N. Mex.	San Juan	6 4 62	Iss.
C. L. McMahon, Inc., Operator, et. al.:					
CI62-375 Lone Star Gas Co.	North Hoover	Okla.	Garvin	3 26 62	Iss.
John G. McMillian, Jr.:					
CI62-631 Phillips Petroleum Co.	Azalea	Tex.	Midland	5 29 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
John G. McMillian, Jr., et. al.:					
CI62-59 Phillips Petroleum Co.	Azalea	Tex.	Midland	3 26 62	Iss.
McNeill Oil & Gas Co.:					
CI62-798 Hope Natural Gas Co.	Murphy*	W. Va.	Ritchie	6 4 62	Iss.
Ralph W. Mace:					
G-20042 Hope Natural Gas Co.	Center District	W. Va.	Gilmer	3 23 62	Iss.
Earl T. Mackey, Agent:					
CI61-862 Arkansas Louisiana Gas Co.	South Hallsville	Tex.	Harrison	5 7 62	Iss.
Malcolm R. Macurdy, Operator, et. al.:					
CI62-527 Cities Service Gas Co.	Undesignated	Kans.	Finney	4 17 62	Iss.
Ruford F. Madera:					
CI62-190 Kansas-Nebraska Natural Gas Co., Inc.	Camrick Area	Okla.	Beaver	5 29 62	Iss.
Magna Oil Corp.:					
G-16748 Northern Natural Gas Co.	Undesignated	Tex.	Hansford	3 26 62	Iss.
Russell Maguire, Operator, et. al.:					
CI62-570 Oklahoma Natural Gas Gathering Corp., et. al.	Ringwood	Okla.	Major	3 30 62	Iss.
Mallard Petroleum, Inc., Operator, et. al.:					
CI62-15 Phillips Petroleum Co.	Azalea	Tex.	Midland	2 21 62	Iss.
Marine Drilling, Inc.:					
CI61-747 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	5 25 62	Iss.
Marion Gas Co.:					
CI61-106 Hope Natural Gas Co.	Ripley	W. Va.	Jackson	1 8 62	Iss.
E. W. Marks, Sr., et. al.:					
CI62-475 United Gas Pipe Line Co.	Pistol Ridge	Miss.	Pearl River	5 23 62	Iss.
Marlin Exploration, Inc., Operator, et. al.:					
CI60-161 Southern Natural Gas Co.	Millhaven	La.	Ouachita	5 25 62	Iss.
M. H. Marr:					
CI62-348 Arkansas Louisiana Gas Co.	Vixen	La.	Caldwell	5 29 62	Iss.
Glen A. Martin, Operator, et. al.:					
CI61-486 Lo-Vaca Gathering Co.	Burnell	Tex.	Karnes	3 25 62	Wtd.
CI61-1013 United Gas Pipe Line Co.	West Weesatche	Tex.	Goliad	5 29 62	Iss.
Martin Oil & Gas Co.:					
CI62-234 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	3 26 62	Iss.
Maxwell Oil Co., Operator, et al.:					
CI61-995 El Paso Natural Gas Co.	Jack Herbert	Tex.	Upton	1 29 62	Iss.
CI62-685 El Paso Natural Gas Co.	Jack Herbert	Tex.	Upton	5 29 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Mayflo Oil Co.:					
CI61-1225 Northern Natural Gas Co.	Camrick Northwest Gas Pool.	Okla.	Beaver	1 8 62	Iss.
CI61-1818 Transwestern Pipeline Co.	South Elmwood	Okla.	Beaver	3 23 62	Iss.
CI62-820 Panhandle Eastern Pipe Line Co.	N. E. Greenough	Okla.	Beaver	6 4 62	Iss.
Mayflo Oil Co., Operator, et al.:					
CI60-261 F.T.F. Gas Corp.	East Spearman, Atoka.	Tex.	Hansford	5 1 62	Iss.
Cecil Meadows, et al.:					
CI61-1144 Equitable Gas Co.	Troy District	W. Va.	Gilmer	1 29 62	Iss.
CI61-1764 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	3 23 62	Iss.
W. L. Meadows:					
CI61-1762 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	2 21 62	Iss.
Edwin G. Meredith, et al.:					
G-18056 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 7 62	Iss.
J. Gregory Merrion, Operator, et al.:					
CI62-186 El Paso Natural Gas Co.	Ballard	N. Mex.	Rio Arriba	4 17 62	Iss.
Metals Service Co.:					
CI62-339 Trunkline Gas Co.	Hitchcock	Tex.	Galveston	5 31 62	Iss.
CI62-505 Hope Natural Gas Co.	Lubeck District	W. Va.	Wood	4 17 62	Iss.
Donald G. Michels:					
CI62-502 Equitable Gas Co.	Union District	W. Va.	Ritchie	4 17 62	Iss.
Mid-America Minerals, Inc.:					
CI61-116 Lone Star Gas Co.	West Morrow	Okla.	Stephens	3 23 62	Iss.
CI62-366 Panhandle Eastern Pipe Line Co.	Six Mile	Okla.	Beaver	4 17 62	Iss.
Mid-American Trust, Inc., et al.:					
CI62-857 Hope Natural Gas Co.	Union District	W. Va.	Clay	6 4 62	Iss.
Midway Oil Co., et al.:					
CI61-1797 Arkansas Louisiana Gas Co.	Braman Area	Okla.	Kay	2 21 62	Iss.
Midwest Pipe & Supply Co.:					
CI61-1382 Cities Service Gas Co.	Morane	Okla.	Beaver	1 8 62	Iss.
Allerton Miller:					
CI61-139 Equitable Gas Co.	Warren District	W. Va.	Upshur	6 4 62	Iss.
CI61-1402 Equitable Gas Co.	Buckhannon District.	W. Va.	Upshur	6 4 62	Iss.
CI62-522 Cumberland & Allegany Gas Co.	Banks District*	W. Va.	Upshur	5 23 62	Iss.
Forrest B. Miller, et al.:					
G-17812 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	5 1 62	Iss.
Geo. W. Miller, et al.:					
G-10506 Hope Natural Gas Co.	Undesignated	W. Va.	Gilmer	5 1 62	Iss.
G-14661 Hope Natural Gas Co.	Undesignated	W. Va.	Gilmer	5 1 62	Iss.
G-15897 Hope Natural Gas Co.	Sinking Creek District.	W. Va.	Gilmer	5 1 62	Iss.
G-15898 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	5 1 62	Iss.
CI62-877 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	6 4 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER[2], DOCKET NO. AND PURCHASER[3]	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Paul L. Miller:					
CI61-1095 United Gas Pipe Line Co.	Troup Area	Tex.	Cherokee	5 7 62	Iss.
William James Miller:					
CI61-48 Tennessee Gas Transmission Co.	Six Mile	Tex.	Calhoun	1 8 62	Iss.
Kenneth P. Milliken & M. A. Milinovich, et al.:					
CI60-432 El Paso Natural Gas Co.	Gavilan Pictured Cliffs.	N. Mex.	Rio Arriba	5 7 62	Iss.
Roger Milliken, et al.:					
G-19596 Natural Gas Pipeline Co. of America.	North Louise	Tex.	Wharton	4 17 62	Iss.
Bob Miner:					
CI61-1501 Coastal States Gas Producing Co.	Johns	Tex.	Duval	5 23 62	Iss.
David S. Miranda:					
CI61-95 United Fuel Gas Co.	Eaton	Ky.	Martin	5 7 62	Iss.
Maude H. Mitchell:					
G-16775 Mississippi River Fuel Corp.	North Ruston	La.	Lincoln	5 1 62	Iss.
Rex Monahan:					
CI62-423 Kansas-Nebraska Natural Gas Co., Inc.	Columbine	Colo.	Logan	4 17 62	Iss.
W. A. Moncrief, Operator:					
CI62-99 Natural Gas Pipeline Co. of America.	Fairbanks	Tex.	Harris	5 23 62	Iss.
Monsanto Chemical Co.:					
G-17519 United Gas Pipe Line Co.	Ada Area	La.	Bienville	3 21 62	Iss.
CI61-990 Tennessee Gas Transmission Co.	El Ebanito	Tex.	Starr	5 7 62	Iss.
CI61-1174 Arkansas Louisiana Gas Co.	Ada	La.	Bienville	1 29 62	Iss.
CI61-1778 Northern Natural Gas Co.	Hansford	Tex.	Hansford	1 29 62	Iss.
CI62-131 El Paso Natural Gas Co.	Hasin	N. Mex.	San Juan	3 23 62	Iss.
J. Hirman Moore:					
CI61-1135 Northern Natural Gas Co.	Eumont Pool	N. Mex.	Lea	1 29 62	Iss.
M. J. Moran:					
CI61-415 Equitable Gas Co.	Court House District.	W. Va.	Lewis	1 29 62	Iss.
CI62-227 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	3 26 62	Iss.
M. J. Moran, et al.:					
CI61-1670 Hope Natural Gas Co.	Weston	W. Va.	Lewis	2 21 62	Iss.
CI62-341 Equitable Gas Co.	Court House District.	W. Va.	Lewis	3 26 62	Iss.
Jehu Morris Gas Co.:					
G-17750 Penova Interest	Murphy District	W. Va.	Ritchie	5 1 62	Iss.
Winnie Fae Morris, et al.:					
CI62-858 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	6 4 62	Iss.
George W. Moses:					
CI61-1127 Equitable Gas Co.	West Union District.	W. Va.	Doddridge	3 23 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
George W. Moses—Continued					
CI62-618 Columbian Carbon Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
W. H. Mossor:					
G-15442 Equitable Gas Co.	Undesignated	W. Va.	Gilmer	5 1 62	Iss.
G-16913 Equitable Gas Co.	Undesignated	W. Va.	Ritchie	5 7 62	Iss.
G-20311 Equitable Gas Co.	Little Fork	W. Va.	Ritchie	5 1 62	Iss.
G-20312 Equitable Gas Co.	Spruce Creek	W. Va.	Ritchie	5 1 62	Iss.
CI61-500 Barron Kidd	Flora Goff	W. Va.	Ritchie	5 7 62	Iss.
CI61-823 Equitable Gas Co.	Freemans Creek District.	W. Va.	Lewis	3 23 62	Iss.
CI61-1637 Equitable Gas Co.	Freemans Creek District.	W. Va.	Lewis	6 4 62	Iss.
CI62-158 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
CI62-492 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	4 17 62	Iss.
CI62-664 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
CI62-671 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
CI62-679 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
CI62-767 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	5 29 62	Iss.
CI62-817 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	6 4 62	Iss.
CI62-819 Hope Natural Gas Co.	New Milton District.	W. Va.	Doddridge	6 4 62	Iss.
W. H. Mossor, et al.:					
G-16173 Equitable Gas Co.	Undesignated	W. Va.	Ritchie	5 1 62	Iss.
G-18251 Equitable Gas Co.	Mary Britton Farm.	W. Va.	Ritchie	5 1 62	Iss.
CI61-788 Hope Natural Gas Co.	Murphy	W. Va.	Ritchie	5 7 62	Iss
CI62-187 Hope Natural Gas Co.	Glenville District	W. Va.	Gilmer	3 23 62	Iss.
CI62-663 Hope Natural Gas Co.	Sheridan District	W. Va.	Calhoun	5 29 62	Iss.
E. W. Mudge, Jr., et al.:					
G-19793 Southern Union Gathering Co.	Undesignated	N. Mex.	San Juan	4 17 62	Iss.
G-19794 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	4 17 62	Iss.
G-19795 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Jaun	4 17 62	Iss.
G-19796 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	4 17 62	Iss.
G-19797 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	4 17 62	Iss.
T. L. Mullen Co.:					
CI61-1389 Equitable Gas Co.	Meade District*	W. Va.	Upshur	4 17 62	Iss.
R. S. Murray, Jr., et al.:					
G-17299 El Paso Natural Gas Co..	Blanco	N. Mex.	San Juan	5 1 62	Iss.
Musgrove Drilling Co.:					
CI61-1698 Kansas-Nebraska Natural Gas Co., Inc.	Hugoton	Kans.	Finney	2 21 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Musgrove Drilling Co., Operator, et al.:					
CI62-554 Panhandle Eastern Pipe Line Co.	Undesignated	Kans.	Meade	4 17 62	Iss.
Mutual Drilling Co., Inc.:					
CI62-11 Equitable Gas Co.	Skin Creek District	W. Va.	Lewis	2 21 62	Iss.
I. Nadel, et al.:					
CI61-1089 Panhandle Eastern Pipe Line Co.	Wil	Kans.	Edwards	1 29 62	Iss.
Nafco Oil & Gas, Inc.:					
CI61-1598 Northern Natural Gas Co.	Hugoton	Kans.	Stevens	5 7 62	Iss.
Nafco Oil & Gas, Inc., et al.:					
G-19841 Northern Natural Gas Co.	Undesignated	Tex.	Ochiltree	4 17 62	Iss.
Nafco Oil & Gas, Inc., Operator, et al.:					
CI61-1181 Northern Natural Gas Co.	R. H. F. Morrow	Tex.	Ochiltree	3 23 62	Iss.
National Cooperative Refinery Association:					
CI62-1001 Montana-Dakota Utilities Co.	Byron Area	Wyo.	Big Horn	6 4 62	Iss.
CI62-1002 North Central Gas Co.	Wallace Creek Area	Wyo.	Natrona	6 4 62	Iss.
National Cooperative Refinery Association, et al.:					
G-19370 Wunderlich Development Co.	Undesignated	Okla.	Kay	3 26 62	Iss.
National Producers, Inc., et al.:					
CI62-828 Hope Natural Gas Co.	Greenbrier District	W. Va.	Doddridge	6 4 62	Iss.
Durell Nealy, Operator, et al.:					
CI62-640 Hope Natural Gas Co.	Troy District	W. Va.	Gilmer	5 29 62	Iss.
Holly Nester:					
CI60-95 Hope Natural Gas Co.	Sheridan District	W. Va.	Calhoun	5 1 62	Iss.
CI61-239 Hope Natural Gas Co.	Lea District	W. Va.	Calhoun	5 7 62	Iss.
CI61-242 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	5 7 62	Iss.
CI61-1274 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	1 8 62	Iss.
CI61-1493 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	1 8 62	Iss.
CI61-1505 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	6 15 62	Wtd.
CI62-239 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	5 29 62	Iss.
CI62-728 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	5 29 62	Iss.
CI62-744 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	5 29 62	Iss.
CI62-873 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	6 4 62	Iss.
Joseph E. Newman, Operator:					
CI61-1820 Northern Natural Gas Co.	Belprie	Kans.	Edwards	2 21 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCERS, DOCKET NO. AND PURCHASERS	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Joseph E. Newman, Operator, et al.:					
CI61-1658 Panhandle Eastern Pipe Line Co.	Carver Robbins*	Kans.	Pratt	3 23 62	Iss.
Arthur L. Nicholson:					
CI62-853 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	6 4 62	Iss.
W. R. Nohe:					
CI61-935 Equitable Gas Co.	Central District	W. Va.	Doddridge	1 29 62	Iss.
Wm. C. & Theodosia M. Nolan:					
CI61-1633 Olin Gas Transmission Corp.	Winsboro	La.	Franklin	5 23 62	Iss.
Northern Natural Gas Producing Co.:					
CI61-986 Northern Natural Gas Co.	Fellsburg	Kans.	Edwards	6 4 62	Iss.
CI61-1676 El Paso Natural Gas Co.	Ingham	Tex.	Crockett	1 8 62	Iss.
CI62-192 Northern Natural Gas Co.	Harper Ranch	Kans.	Clark	5 29 62	Iss.
Northern Pump Co.:					
G-11225 Northern Natural Gas Co.	Hugoton	Kans.	Finney	3 26 62	Iss.
G-18922 United Gas Pipe Line Co.	Cabeza Creek Area	Tex.	Goliad	3 20 62	Rej.
Northern Pump Co., Operator, et al.:					
CI61-1450 Texas Eastern Transmission Corp.	Goree	Tex.	Bee	1 8 62	Iss.
CI61-1807 Texas Eastern Transmission Corp.	Mercedes	Tex.	Hidalgo	1 29 62	Iss.
James R. Nowery and B. M. Nowery Jr.:					
G-16190 United Gas Pipe Line Co.	Ada Area	La.	Bienville	3 21 62	Iss.
The Nueces Co., Operator:					
CI62-101 El Paso Natural Gas Co.	Stockton	Tex.	Pecos	5 31 62	Iss.
John C. O'Leary:					
CI61-99 Tennessee Gas Transmission Co.	Little Flower	Tex.	Victoria	1 8 62	Iss.
Joseph I. O'Neill, Jr., Operator, et al.:					
CI62-224 El Paso Natural Gas Co.	Azalea	Tex.	Midland	5 7 62	Iss.
Odessa Natural Gasoline Co.:					
CI61-1319 Transwestern Pipeline Co.	Follett*	Tex.	Lipscomb	2 21 62	Iss.
CI61-1482 Transwestern Pipeline Co.	Undesignated	N. Mex.	Eddy	2 21 62	Iss.
Odessa Natural Gasoline Co., Operator, et al.:					
CI62-707 Phillips Petroleum Co.	Undesignated	Tex.	Upton	5 7 62	Iss.
The Ohio Oil Co.:					
CI61-1072 El Paso Natural Gas Co.	Cutz Canyon Area	N. Mex.	San Juan	2 21 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
The Ohio Oil Co., Operator, et al.:					
G-15385 United Gas Pipe Line Co.	Ada Area	La.	Bienville	3 21 62	Iss.
Oil Development Co. of Texas:					
G-16739 Northern Natural Gas Co.	Hansford	Tex.	Hansford	3 26 62	Iss.
Oil Well Drilling Co., et al.:					
G-18311 El Paso Natural Gas Co.	Eumont	N. Mex.	Lea	3 23 62	Iss.
Oklahoma Natural Gas Co.:					
CI62-7 Northern Natural Gas Co.	Laverne*	Okla.	Beaver	3 23 62	Iss.
Oklahoma Natural Gas Co., Operator, et al.:					
CI61-1639 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
CI61-1781 Arkansas Louisiana Gas Co.	Deep Chickasha	Okla.	Grady	3 23 62	Iss.
Oklahoma Natural Gas Gathering Corp.:					
CI61-1408 Cities Service Gas Co.	Ringwood	Okla.	Major	3 30 62	Iss.
Howard Olsen Development Co., Operator, et al.:					
CI61-939 Transwestern Pipeline Co.	Atoka Field	N. Mex.	Eddy	1 29 62	Iss.
R. Olsen, Operator, et al.:					
CI61-1602 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex.	Lea	1 29 62	Iss.
Olympic Oil Co.:					
G-19347 Wunderlich Development Co.	Undesignated	Okla.	Kay	3 26 62	Iss.
G-19348 Wunderlich Development Co.	Undesignated	Okla.	Kay	3 26 62	Iss.
G-19349 Wunderlich Development Co.	Undesignated	Okla.	Kay	3 26 62	Iss.
G-19350 Wunderlich Development Co.	Undesignated	Okla.	Kay	3 26 62	Iss.
G-19351 Wunderlich Development Co.	Undesignated	Okla.	Kay	3 26 62	Iss.
P & J Development Co., Inc.:					
CI61-1194 Hope Natural Gas Co.	Elk District	W. Va.	Kanawha	1 29 62	Iss.
CI61-1503 Hope Natural Gas Co.	McClellan District	W. Va.	Doddridge	1 8 62	Iss.
CI62-24 Hope Natural Gas Co.	Eagle District	W. Va.	Harrison	2 21 62	Iss.
CI62-167 Hope Natural Gas Co.	Clark District	W. Va.	Harrison	3 23 62	Iss.
CI62-754 Hope Natural Gas Co.	Eagle District	W. Va.	Harrison	5 29 62	Iss.
CI62-787 Hope Natural Gas Co.	Eagle District	W. Va.	Harrison	5 29 62	Iss.
Pace Bower Construction Co.:					
CI61-1299 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	1 29 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Pace Bower Construction Co—Continued					
CI61-1758 Hope Natural Gas Co.	Collins Settlement District.	W. Va.	Lewis	1 29 62	Iss.
Palm Petroleum Corp., Operator, et al.:					
CI62-48 United Gas Pipe Line Co.	Weesatche	Tex.	Goliad	2 21 62	Iss.
Milo T. Palmer:					
G-15437 Arkansas Louisiana Gas Co.	Colquitt	La.	Claiborne	5 1 62	Iss.
Pan American Petroleum Corp.:					
G-15388 Transwestern Pipeline Co.	Ute Dome	N. Mex.	San Juan	3 29 62	Wtd.
G-19277 El Paso Natural Gas Co.	Tip Top-Hogsback	Wyo.	Sublette*	6 11 62	Iss.
CI60-236 El Paso Natural Gas Co.	Blinebry	N. Mex.	Lea	5 29 62	Iss.
CI61-74 Mountain Fuel Supply Co.	Alkali Creek Structure Area	Wyo.	Sweetwater	1 8 62	Iss.
CI61-516 Michigan Wisconsin Pipe Line Co.	Woodward Area	Okla.	Dewey*	3 7 62	Iss.
CI61-1307 El Paso Natural Gas Co.	Huerfano Gallup	N. Mex.	San Juan	1 29 62	Iss.
CI61-1387 United Gas Pipe Line Co.	North La Ward	Tex.	Jackson	1 8 62	Iss.
Panhandle Development Co., Inc., Operator:					
CI61-496 Phillips Petroleum Co.	Hugoton	Tex.	Sherman	5 7 62	Iss.
Panhandle Development Co., Inc., Operator, et al.:					
CI61-1151 Panhandle Eastern Pipe Line Co.	South Kismet	Kans.	Seward	1 29 62	Iss.
CI61-1386 Michigan Wisconsin Pipe Line Co.	Greenough	Okla.	Beaver	1 29 62	Iss.
CI61-1624 Panhandle Eastern Pipe Line Co.	Undesignated	Kans.	Seward	1 8 62	Iss.
CI61-1771 Panhandle Eastern Pipe Line Co.	Undesignated	Kans.	Meade	1 29 62	Iss.
Irving Pasternak:					
CI62-79 El Paso Natural Gas Co.	Undesignated	Colo.	La Plata	2 21 62	Iss.
CI62-80 El Paso Natural Gas Co.	Undesignated	Colo.	La Plata	2 21 62	Iss.
Patoil Corp., Operator, et al.:					
CI62-97 Texas Eastern Transmission Corp.	S.W. Helen Gohlke	Tex.	Victoria	5 29 62	Iss.
H. I. Patterson & R. E. Williams:					
CI62-284 Arkansas Louisiana Gas Co.	Longwood	La.	Caddo	5 29 62	Iss.
W. H. Peachee, et al.:					
CI62-735 Wunderlich Development Co.	Undesignated	Kans.	Sumner	5 29 62	Iss.
CI62-748 Wunderlich Development Co.	Undesignated	Kans.	Sumner	5 29 62	Iss.
CI62-749 Wunderlich Development Co.	Undesignated	Kans.	Sumner	5 29 62	Iss.
Peake Petroleum Co.:					
CI62-249 United Fuel Gas Co.	Stafford District	W. Va.	Mingo	3 26 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Glenn W. Peel:					
CI61-366 Panhandle Eastern Pipe Line Co.	Wil	Kans	Stafford	5 7 62	Iss.
Peerless Oil & Gas Co., Operator, et al.:					
CI62-250 Natural Gas Pipeline Co. of America.	Undesignated	Okla	Texas	5 29 62	Iss.
CI62-251 Northern Natural Gas Co.	Undesignated	Okla	Texas	5 29 62	Iss.
Neville G. Penrose, Inc.:					
CI61-203 Valley Gas Transmission, Inc.	Ft. Merrill	Tex	Live Oak	5 23 62	Iss.
Neville G. Penrose, Inc., Operator:					
CI61-202 Phillips Petroleum Co.	Fradean	Tex	Upton	1 8 62	Iss.
The Permian Corp., et al.:					
CI60-180 El Paso Natural Gas Co.	Undesignated	N. Mex	San Juan	5 1 62	Iss.
Petroleum Drilling Corp., et al.:					
CI62-874 Hope Natural Gas Co.	Union District	W. Va	Ritchie	6 4 62	Iss.
Petroleum Exploration, Inc. of Texas, et al.:					
CI61-669 Transwestern Pipe-Line Co.	Share-Mississippian	Tex	Ochiltree	2 21 62	Iss.
CI62-657 Northern Natural Gas Co.	Morrow	Okla	Beaver	5 23 62	Iss.
Petroleum, Inc.:					
G-16572 Panhandle Eastern Pipe Line Co.	Undesignated	Okla	Texas	3 26 62	Iss.
G-19199 Kansas-Nebraska Natural Gas Co., Inc.	Bijou	Colo	Morgan	3 26 62	Iss.
CI62-41 Natural Gas Pipe-Line Co. of America	Brillhart Upper Morrow	Tex	Hansford	6 4 62	Iss.
Petroleum, Inc., Operator, et al.:					
CI60-443 El Paso Natural Gas Co.	Gavilan Pictured Cliffs	N. Mex	Rio Arriba	5 7 62	Iss.
Petroleum Management, Inc.:					
G-19061 Wunderlich Development Co.	Undesignated	Kans	Cowley	5 1 62	Iss.
Loyce Phillips:					
CI61-1136 United Gas Pipe Line Co.	Mt. Selman	Tex	Cherokee	5 7 62	Iss.
Phillips Petroleum Co.:					
G-11158 Magnolia Petroleum Co.	Undesignated	Okla	Carter	5 14 62	Rej.
G-16610 United Gas Pipe Line Co.	Wyrick	Tex	Refugio	3 26 62	Iss.
G-16915 Wunderlich Development Co.	S. E. Autwine	Okla	Kay	3 26 62	Iss.
CI62-65 Arkansas Louisiana Gas Co.	Deep Chickasha	Okla	Grady	3 23 62	Iss.
CI62-575 Northern Natural Gas Co.	Northeast Sitka	Kans	Clark	6 4 62	Iss.
CI62-929 Northern Natural Gas Co.	Azalea	Tex	Midland	6 4 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
D. W. Pickett, Operator, et al.:					
CI61-1255 Tennessee Gas Transmission Co.	San Salvador	Tex	Hidalgo	5 25 62	Iss.
D. W. Pickett, Jr., Operator, et. al.:					
CI61-594 Tennessee Gas Transmission Co.	Auga Dulce	Tex	Nueces	5 25 62	Iss.
Pickrell Drilling Co., et al.:					
CI61-1349 Plateau Natural Gas Co.	Northwest Sharon	Kans	Barber	6 5 62	Rej.
Pickrell Drilling, Operator, et al.:					
G-18244 Cities Service Gas Co.	Undesignated	Kans	Barber	3 23 62	Iss.
L. G. Pigott:					
CI62-132 Hope Natural Gas Co.	Grant District	W. Va	Doddridge	5 25 62	Iss.
Pioneer Petroleum, Inc.:					
CI62-741 Hope Natural Gas Co.	Collins Settlement District	W. Va	Lewis	5 29 62	Iss.
Pioneer Production Corp.:					
CI62-113 Natural Gas Pipe-Line Co. of America.	West Chester	Okla	Woodward	3 23 62	Iss.
Pioneer Production Corp., Operator, et al.:					
CI62-50 Northern Natural Gas Co.	Undesignated	Tex	Ochiltree	2 21 62	Iss.
R. A. Pitzer:					
CI61-905 Valley Gas Transmission, Inc.	Lagarto	Tex	Live Oak	5 23 62	Iss.
H. O. Pool, et al.:					
CI62-447 El Paso Natural Gas Co.	Canyon Largo	N. Mex	Rio Arriba	4 17 62	Iss.
W. E. Pope, et al.:					
CI62-241 Equitable Gas Co	Centerville District	W. Va	Tyler	5 23 62	Iss.
Clarence E. Powell, et al.:					
CI61-1292 Equitable Gas Co	Central District	W. Va	Doddridge	1 29 62	Iss.
CI62-182 Hope Natural Gas Co.	New Milton District.	W. Va	Doddridge	5 29 62	Iss.
CI62-743 Hope Natural Gas Co.	New Milton District.	W. Va	Doddridge	5 29 62	Iss.
M. F. Powers, Estate:					
CI62-583 Cities Service Gas Co.	Hugoton	Kans	Kearny	5 7 62	Iss.
Prairie States Petroleum Corp., Operator, et al.:					
CI62-36 Transwestern Pipeline Co.	Worsham	Tex	Reeves *	3 23 62	Iss.
Ferrell L. Prior:					
CI61-387 Equitable Gas Co	Court House District.	W. Va	Lewis	5 7 62	Iss.
CI61-603 Equitable Gas Co	Belle Sandy No. 1	W. Va	Gilmer	5 7 62	Iss.
CI61-1577 Equitable Gas Co	Court House District.	W. Va	Lewis	2 21 62	Iss.
CI62-84 Equitable Gas Co	Court House District	W. Va	Lewis	3 23 62	Iss.
CI62-565 Equitable Gas Co	Hackers Creek District.	W. Va	Lewis	4 17 62	Iss.
CI62-611 Hope Natural Gas Co.	Holly District	W. Va	Braxton	6 4 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Ferrell L. Prior, et al.:					
CI61-105 Hope Natural Gas Co.	Court House District.	W. Va.	Lewis	1 8 62	Iss.
CI61-395 Equitable Gas Co.	West Union District.	W. Va.	Doddridge	1 29 62	Iss.
CI61-1155 Equitable Gas Co.	Court House District.	W. Va.	Lewis	1 29 62	Iss.
CI61-1156 Equitable Gas Co.	Collins Settlement District.	W. Va.	Lewis	1 29 62	Iss.
CI61-1232 Equitable Gas Co.	West Union District.	W. Va.	Doddridge	1 8 62	Iss.
CI61-1477 Equitable Gas Co.	Court House District.	W. Va.	Lewis	1 8 62	Iss.
CI61-1600 Equitable Gas Co.	Court House District.	W. Va.	Lewis	1 8 62	Iss.
L. W. Prunty:					
G-19237 Penova Interest	Grant District	W. Va.	Ritchie	3 26 62	Iss.
CI62-506 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	6 4 62	Iss.
Pubco Petroleum Corp.:					
G-20138 El Paso Natural Gas Co.	Blanco	N. Mex.	San Juan	5 1 62	Iss.
The Pure Oil Co.:					
CI61-1071 Arkansas Louisiana Gas Co.	Calhoun	La.	Ouachita	1 29 62	Iss.
CI62-232 Lone Star Gas Co.	Big Mineral Creek	Tex.	Grayson	5 31 62	Iss.
CI62-736 Cities Service Gas Co.	South Sterling	Okla.	Comanche	5 29 62	Iss.
The Pure Oil Co., Operator, et al.:					
CI62-232 Lone Star Gas Co.	Undesignated	Okla.	Stephens	5 31 62	Iss.
Homer Queen, et al.:					
CI61-1761 Hope Natural Gas Co.	Warren District	W. Va.	Upshur	2 21 62	Iss.
CI62-769 Hope Natural Gas Co.	Skin Creek District.	W. Va.	Lewis	5 29 62	Iss.
R.A.D. Corp.:					
G-14430 Hope Natural Gas Co.	Union District	W. Va.	Harrison	1 12 62	Iss.
R. A. F. Natural Gas Corp.:					
CI61-821 Arkansas Louisiana Gas Co.	Longwood	La.	Caddo	5 23 62	Iss.
A. C. Radford:					
CI62-876 Hope Natural Gas Co.	Glenville District	W. Va.	Gilmer	6 4 62	Iss.
Ramada Oil & Gas Co.:					
CI62-1469 Tennessee Gas Transmission Co.	Northeast Loma Novia Wilcox.	Tex.	Duval	6 22 62	Rej.
Rancho Grande Oil Co.:					
CI62-116 Tennessee Gas Transmission Co.	North Ross	Tex.	Starr	5 25 62	Iss.
James S. Ray, et al.:					
CI62-672 United Fuel Gas Co.	L. E. & L. R. Belcher.	W. Va.	Kanawha	5 31 62	Iss.
Paul L. Read:					
G-17552 Arkansas Louisiana Gas Co.	North Ruston	La.	Lincoln	4 17 62	Iss.
Redfern Oil Co.:					
G-15447 El Paso Natural Gas Co.	Denton	N. Mex.	Lea	5 25 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Val R. Reese & Associates, Inc., Operator:					
CI61-991 El Paso Natural Gas Co.	Undesignated	N. Mex.	Rio Arriba	2 21 62	Iss.
Reedwell Development Co.:					
CI61-1593 Hope Natural Gas Co.	Grant District	W. Va.	Ritchie	1 8 62	Iss.
James A. Rehler, Operator, et al.:					
CI62-189 United Gas Pipe Line Co.	Melrose	Tex.	Goliad	5 25 62	Iss.
E. E. Reigle:					
G-19418 El Paso Natural Gas Co.	Spraberry Trend	Tex.	Glasscock	5 29 62	Iss.
G-19567 El Paso Natural Gas Co.	Spraberry Trend	Tex.	Glasscock	5 7 62	Iss.
Rex Oil & Gas Co.:					
CI62-533 Hope Natural Gas Co., et al.	Troy District	W. Va*	Clay*	5 25 62	Iss.
William B. Rezek, et al.:					
CI62-641 Hope Natural Gas Co	Grant Districts*	W. Va.	Ritchie*	5 29 62	Iss.
B. M. Rhine, et al.:					
CI61-1227 Equitable Gas Co.	Charles Burke No.1	W. Va.	Gilmer	1 8 62	Iss.
C. E. Richner, et al.:					
CI62-143 Hope Natural Gas Co.	Baileysville District	W. Va.	Wyoming	5 29 62	Iss.
Ridgmorr Oil Co., Operator, et al.:					
CI62-212 Northern Natural Gas Co.	Harbaugh	Tex.	Ochiltree	3 26 62	Iss.
Pat J. Riley & Louise B. Riley:					
CI62-818 Cities Service Gas Co.	Guymon-Hugoton	Okla.	Texas	5 23 62	Iss.
Patricia L. Riley:					
CI62-823 Cities Service Gas Co.	Undesignated	Okla.	Texas	5 31 62	Iss.
Rio Sabine, Inc.:					
CI61-1379 Arkansas Louisiana Gas Co.	North Carthage	Tex.	Panola*	2 21 62	Iss.
George T. Ritsos:					
CI61-1198 United Natural Gas Co.	Undesignated	Pa.	McKean	1 29 62	Iss.
Elias Ritts, et al.:					
G-15346 South Penn Oil Co.	Sherman & Burning Springs District.	W. Va.	Calhoun*	5 1 62	Iss.
Jewel Daffin Rivers, et al.:					
CI61-1241 Texas Gas Transmission Corp.#	Calhoun Area	La.	Ouachita	1 29 62	Iss.
A. F. Roberts, Jr., Operator, et al.:					
CI62-285 El Paso Natural Gas Co.	Jalmat	N. Mex.	Lea	5 29 62	Iss.
D. D. Roberts:					
CI62-869 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	6 4 62	Iss.
D. D. Roberts, et al.:					
CI61-1113 Hope Natural Gas Co.	West Union District.	W. Va.	Doddridge	1 8 62	Iss.
Glen W. Roberts:					
CI61-1170 Hope Natural Gas Co.	Burning Springs District.	W. Va.	Wirt	1 29 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER[3], DOCKET NO. AND PURCHASER[3]	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION[1]
Robert F. Roberts:					
G-19810 United Gas Pipe Line Co.	Undesignated	La.	Lincoln	3 21 62	Iss.
CI62-816 United Gas Pipe Line Co.	Sligo	La.	Bossier	6 4 62	Iss.
E. A. Robertson:					
CI61-1769 Hope Natural Gas Co.	Union District	W. Va.	Clay	3 26 62	Iss.
John R. Robinson, et al.:					
CI61-1440 Hope Natural Gas Co.	DeKalb	W. Va.	Gilmer	1 8 62	Iss.
CI62-474 Hope Natural Gas Co.	Troy District	W. Va.	Gilmer	4 17 62	Iss.
CI62-880 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	6 4 62	Iss.
L. L. Robinson, et al.:					
G-16457 United Gas Pipe Line Co.	Ada Area	La.	Bienville	3 21 62	Iss.
Rock Island Oil & Refining Co., Inc.:					
CI60-181 Cities Service Gas Co.	Hugoton	Kans.	Seward	5 1 62	Iss.
CI61-478 Plateau Natural Gas Co.	Undesignated	Kans.	Kingman	5 18 62	Wtd.
CI61-1563 El Paso Natural Gas Co.	North Scarborough	Tex.	Winkler	2 21 62	Iss.
E. G. Rodman, Operator, et al.:					
CI62-578 Northern Natural Gas Co.	Hansford	Tex.	Hansford	4 17 62	Iss.
Rodman, Late & Noel:					
G-14752 El Paso Natural Gas Co.	Spraberry Trend Area.	Tex.	Regan	3 26 62	Iss.
W. Leslie Rogers:					
CI61-1328 Equitable Gas Co.	Central District	W. Va.	Doddridge	3 26 62	Iss.
Roy B. Rollins:					
CI62-867 Hope Natural Gas Co.	Union District	W. Va.	Harrison	6 4 62	Iss.
D. H. Rowland:					
CI61-1561 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
Joe Rubin & Sons:					
CI61-1675 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	1 29 62	Iss.
Robert T. Rushmore:					
CI61-721 Michigan Wisconsin Pipe Line Co.	Laverne	Okla.	Harper	3 22 62	Rej.
Otis Russell, Operator, et al.:					
CI62-20 Tennessee Gas Transmission Co.	West El Campo Area.	Tex.	Wharton	2 21 62	Iss.
Paul F. Rutledge, Operator, et, al.:					
CI61-1790 El Paso Natural Gas Co.	Devils Fork	N. Mex.	Rio Arriba	3 23 62	Iss.
St. Clair Oil Co.:					
CI61-420 Equitable Gas Co.	Collins Settlement[9]	W. Va.	Lewis	1 29 62	Iss.
CI61-421 Equitable Gas Co.	Hackers Creek District.	W. Va.	Lewis	1 29 62	Iss.
CI61-1242 Equitable Gas Co.	Skin Creek District	W. Va.	Lewis	1 29 62	Iss.
CI62-94 Equitable Gas Co.	Skin Creek District	W. Va.	Lewis	3 23 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Samedan Oil Corp.:					
CI62-264 Transwestern Pipeline Co.	Undesignated	Okla.	Beaver	4 4 62	Wtd.
CI62-862 Lone Star Gas Co.	Stage Stand	Okla.	Stephens	6 4 62	Iss.
Sands Industries, Inc., Operator, et al.:					
CI62-526 Cities Service Gas Co.	South Newkirk	Okla.	Kay	4 17 62	Iss.
Santana Petroleum Corp., et al.:					
CI62-601 Phillips Petroleum Co.	South Stiles Fusselman.	Tex.	Reagan	4 17 62	Iss.
Santiago Oil & Gas Co., Operator, et al.:					
CI62-784 Transwestern Pipeline Co.	Crawar	Tex.	Crane	5 29 62	Iss.
Saturn Oil & Gas Co., Inc., Operator, et al.:					
CI62-28 Panhandle Eastern Pipe Line Co.	Hugoton Area	Kans.	Grant*	5 7 62	Iss.
Fred Scandola:					
CI61-405 Equitable Gas Co.	Union District	W. Va.	Ritchie	6 4 62	Iss.
Schermerhorn Oil Corp., Operator, et al.:					
G-19327 El Paso Natural Gas Co.	Undesignated	N. Mex.	Lea	5 25 62	Wtd.
Frank A. Schultz:					
CI61-817 El Paso Natural Gas Co.	Undesignated Dakota.	N. Mex.	San Juan*	5 7 62	Iss.
Scott Williams Gas Co. No. 1:					
G-10554 South Penn Oil Co.	DeKalb District	W. Va.	Gilmer	5 1 62	Iss.
Joseph E. Seagram & Sons, Inc.:					
CI62-370 Texas Eastern Transmission Corp.	North Gillis	La.	Calcasieu	4 27 62	Iss.
H. F. Sears:					
CI62-30 Colorado Interstate Gas Co.	West Panhandle	Tex.	Hutchinson*	2 21 62	Iss.
See-Tee Mining Corp.:					
CI61-1523 El Paso Natural Gas Co.	Twin Mounds Area	N. Mex.	San Juan	2 21 62	Iss.
Service Drilling Co., et al.:					
CI61-326 The Shamrock Oil & Gas Corp.	Dunway Lease	Tex.	Hutchinson	5 7 62	Iss.
Service Gas Products Co.:					
CI62-739 Lone Star Gas Co.	Undesignated	Okla.	Garvin	5 29 62	Iss.
Shaff Minerals Associated, Inc.:					
CI62-553 Cumberland and Allegheny Gas Co.	Freemans Creek District.	W. Va.	Lewis	4 17 62	Iss.
Shaff Minerals Associates, Inc., et al.:					
CI62-855 Hope Natural Gas Co.	Freemans Creek Distirct.	W. Va.	Lewis	6 4 62	Iss.
Milton F. Shaffer, Operator:					
CI61-33 Northern Natural Gas Co.	Hansford Lower Morrow.	Tex.	Ochiltree	5 7 62	Iss.
Milton F. Shaffer, Operator, et al.:					
CI62-523 Northern Natural Gas Co.	Farnsworth Lower Missouri Gas.	Tex.	Ochiltree	6 4 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
The Shamrock Oil & Gas Corp.:					
CI62-121 Northern Natural Gas Co.	Undesignated	Tex.	Hansford	5 29 62	Iss.
CI62-367 Natural Gas Pipeline Co. of America.	Undesignated	Tex.	Ochiltree	4 17 62	Iss.
Donald Sharp, Operator, et al.:					
CI62-577 Banquete Gas Co.	Odem	Tex.	San Patricio	4 17 62	Iss.
W. H. Sharp, Operator, et al.:					
G-15317 Shell Oil Co.	North Mt. Hope	Colo.	Logan	4 17 62	Iss.
James I. Shearer:					
CI62-755 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	5 29 62	Iss.
James I. Shearer, et al.:					
CI61-1208 Equitable Gas Co.	Central District	W. Va.	Doddridge	1 8 62	Iss.
CI61-1576 Equitable Gas Co.	Central District	W. Va.	Doddridge	1 8 62	Iss.
CI61-1805 Equitable Gas Co.	Central District	W. Va.	Doddridge	1 29 62	Iss.
CI62-415 Equitable Gas Co.	Central District	W. Va.	Doddridge	5 7 62	Iss.
Shell Oil Co.:					
G-12663 Northern Natural Gas Co.	Hugoton	Kans.	Finney	5 1 62	Iss.
CI61-524 Michigan Wisconsin Pipe Line Co.	Woodward Area	Okla.	Woodward*	2 7 62	Iss.
CI61-660 Panhandle Eastern Pipe Line Co.	Undesignated	Okla.	Beckham	1 15 62	Iss.
CI61-1430 El Paso Natural Gas Co.	Brown-Bassett Ellenburger.	Tex.	Terrell	1 8 62	Iss.
CI62-58 Transwestern Pipeline Co.	Crawar	Tex.	Crane*	3 26 62	Iss.
CI62-86 El Paso Natural Gas Co.	Spraberry	Tex.	Glasscock	5 7 62	Iss.
CI62-255 Texas Eastern Transmission Corp.	Sligo	La.	Bossier	3 9 62	Iss.
CI62-353 Lone Star Gas Co.	Manziel	Tex.	Wood	4 17 62	Iss.
CI62-510 United Gas Pipe Line Co.	Little Creek Plant	Miss.	Lincoln*	5 23 62	Iss.
Shell Oil Co., Operator:					
CI61-1143 Texas Eastern Transmission Corp.	Siloam	Miss.	Clay	1 29 62	Iss.
Shell Oil Co., Operator, et al.:					
CI62-468 Lone Star Gas Co.	Stage Stand	Okla.	Stephens	4 17 62	Iss.
James C. Sherrill, et al.:					
CI62-660 Colo. Interstate Gas Co.	West Panhandle	Tex.	Potter	5 29 62	Iss.
Shiprock Industries, Inc., Operator, et al.:					
CI62-581 El Paso Natural Gas Co.	San Juan Basin	N. Mex.	San Juan	5 23 62	Iss.
Charles H. Sickrey, et al.:					
CI62-364 El Paso Natural Gas Co.	Undesignated	Okla.	Beckham	5 29 62	Iss.
E. C. Sidwell, et al.:					
CI61-965 El Paso Natural Gas Co.	East Panhandle	Tex.	Collinsworth	2 21 62	Iss.
Hayden Simmons Oil & Gas Co., et al.:					
CI62-719 South Penn Oil Co.	Spencer District	W. Va.	Roane	5 29 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Sinclair Oil & Gas Co.:					
G–18192 El Paso Natural Gas Co.	Sweetie Peck	Tex.	Midland	5 1 62	Iss.
G–19036 Northern Natural Gas Co.	East Camrick*	Tex.	Beaver*	6 4 62	Iss.
CI60–460 Natural Gas Pipeline Co. of America.	Spearman	Tex.	Hansford	5 7 62	Iss.
CI61–691 Michigan Wisconsin Pipe Line Co.	Woodward Area	Okla.	Woodward*	3 7 62	Iss.
CI61–1168 El Paso Natural Gas Co.	W. Langlie-Mattix	N. Mex.	Lea	5 23 62	Iss.
CI61–1191 United Gas Pipe Line Co.	Henderson	Tex.	Rusk	5 23 62	Iss.
CI61–1210 United Gas Pipe Line Co.	East Texas	Tex.	Gregg	5 7 62	Iss.
CI61–1401 Transwestern Pipeline Co.	Worsham	Tex.	Reeves	2 21 62	Iss.
CI61–1766 Panhandle Eastern Pipe Line Co.	Guymon-Hugoton	Okla.	Texas	1 29 62	Iss.
CI62–96 El Paso Natural Gas Co.	Brown-Bassett	Tex.	Terrell	2 21 62	Iss.
CI62–160 El Paso Natural Gas Co.	King Plant	N. Mex.	Lea	5 25 62	Iss.
CI62–287 El Paso Natural Gas Co.	Brown-Bassett-Non-Ellenberger.	Tex.	Terrell	5 23 62	Iss.
CI62–296 Texas Eastern Transmission Corp.	Sligo	La.	Bossier	3 9 62	Iss.
CI62–297 Texas Eastern Transmission Corp.	Sligo	La.	Bossier	3 9 62	Iss.
CI62–531 Northern Natural Gas Co.	Harper Ranch*	Kans.	Clark	4 17 62	Iss.
CI62–723 Cities Service Gas Co.	Hugoton	Kans.	Finney	5 29 62	Iss.
Sinclair Oil & Gas Co., Operator:					
CI61–949 Lone Star Gas Co.	East Durant	Okla.	Bryan	3 23 62	Iss.
Sinclair Oil & Gas Co., Operator, et al.:					
G–20358 H. L. Hunt & Estate of Lyda Bunker Hunt.	North Lansing	Tex.	Harrison	5 1 62	Iss.
CI62–33 United Gas Pipe Line Co.	East Texas	Tex.	Smith*	5 29 62	Iss.
CI62–34 Wunderlich Development Co.	Vernon North & Hilltop Pool.*	Kans.	Summer*	5 7 62	Iss.
CI62–530 Natural Gas Pipeline Co. of America.	Northeast Alden	Okla.	Caddo	4 17 62	Iss.
Herman Singer:					
CI61–1738 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
Wiley W. Singleton Drilling Co., Inc., Operator, et al.:					
CI61–1390 Valley Gas Transmission, Inc.	Lagarto	Tex.	Live Oak	6 4 62	Iss.
R. J. Sipoha, Agent:					
CI62–427 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	4 17 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
R. J. Sipoha, Agent—Continued					
CI62-428 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	4 17 62	Iss.
Robert J. Sipoha, et al.:					
CI62-300 Hope Natural Gas Co.	Lawford, Union District.	W. Va.	Ritchie	5 29 62	Iss.
CI62-864 Hope Natural Gas Co.	Troy District	W. Va.	Gilmer	6 4 62	Iss.
A. T. Skaer:					
CI61-129 Kansas-Nebraska Natural Gas Co., Inc.	Logan	Colo.	Logan	5 29 62	Iss.
CI62-209 Kansas-Nebraska Natural Gas Co., Inc.	West Minto	Colo.	Logan	3 23 62	Iss.
Skelly Oil Co.:					
G-16744 Kansas-Nebraska Natural Gas Co., Inc.	Cedar Creek	Colo.	Logan	3 26 62	Iss.
G-18880 Natural Gas Pipeline Co. of America.	Camrick Southeast	Okla.	Beaver	3 26 62	Iss.
CI60-108 West Texas Gathering Co.	Emperor	Tex.	Winkler	5 29 62	Iss.
CI61-601 Northern Natural Gas Co.	Undesignated	N. Mex.	Lea	3 26 62	Iss.
CI61-819 Michigan Wisconsin Pipe Line Co.	Woodward Area	Okla.	Woodward*	3 7 62	Iss.
CI61-1795 Panhandle Eastern Pipe Line Co.	Eva Pool Area	Okla.	Texas	1 29 62	Iss.
CI62-701 Cities Service Gas Co.	Hugoton	Kans.	Finney	5 29 62	Iss.
Skelly Oil Co., Operator:					
G-19402 Natural Gas Pipeline Co. of America.	Camrick S.E. Pool	Okla.	Beaver	5 29 62	Iss.
Skelly Oil Co., Operator, et al.:					
CI61-916 Natural Gas Pipeline Co. of America.	West Cement	Okla.	Caddo	4 2 62	Wtd.
Skinner Corp., Operator, et al.:					
CI61-884 Valley Gas Transmission, Inc.	Hinnant	Tex.	Live Oak	5 23 62	Iss.
Skylark Gas Co.:					
CI62-673 Equitable Gas Co.	Grant* Districts	W. Va.	Lewis*	5 29 62	Iss.
William E. Slaughter, Jr., et al.:					
CI61-1739 El Paso Natural Gas Co.	Pegasus Plant	Tex.	Midland*	3 23 62	Iss.
Smith & Barker Oil & Gas Co., Inc.:					
CI61-98 Hope Natural Gas Co.	Sherman District	W. Va.	Calhoun	1 8 62	Iss.
Carl E. Smith, Inc.:					
CI61-1263 Hope Natural Gas Co.	West Union District.	W. Va.	Doddridge	1 8 62	Iss.
CI62-777 Hope Natural Gas Co.	Grant District	W. Va.	Doddridge	5 29 62	Iss.
Smith Development Co., Operator, et al.:					
CI62-417 Panhandle Eastern Pipe Line Co.	Greenough	Okla.	Beaver	4 17 62	Iss.
Edward M. Smith:					
CI62-338 Hope Natural Gas Co.	Sherman District	W. Va.	Calhoun	3 26 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER[2], DOCKET NO. AND PURCHASER[2]	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Edward M. Smith, et al.:					
CI62-294 Hope Natural Gas Co.	Sherman District	W. Va.	Calhoun	5 29 62	Iss.
Jas. F. Smith, Operator, et al.:					
CI62-710 Panhandle Eastern Pipe Line Co.	Mocane	Okla.	Beaver	5 29 62	Iss.
J. M. L. Smith, et al.:					
CI61-1776 Equitable Gas Co.	West Union District.	W. Va.	Doddridge	1 29 62	Iss.
Walter E. Smith:					
CI62-773 Hope Natural Gas Co.	Sherman District	W. Va.	Calhoun	5 29 62	Iss.
CI62-776 Hope Natural Gas Co.	Sheridan District	W. Va.	Calhoun	5 29 62	Iss.
Walter E. Smith, et al.:					
CI62-162 Hope Natural Gas Co.	Sherman District	W. Va.	Calhoun	5 29 62	Iss.
Gene A. Smitherman:					
CI61-1751 Tennessee Gas Transmission Co.	Classcock	Tex.	Colo.	5 29 62	Iss.
A. M. Snider:					
CI62-835 South Penn Oil Co.	Clay District	W. Va.	Monongalia	6 4 62	Iss.
Fred Snyder Co.:					
CI62-789 South Penn Oil Co.	Church District	W. Va.	Wetzel	5 29 62	Iss.
Socony Mobil Oil Co., Inc.:					
G-13780 Transcontinental Gas Pipe Line Corp.	High Island Block 10.	Tex.	Jefferson	2 9 62	Iss.
G-16522 Arkansas Louisiana Gas Co.	North Ruston	La.	Lincoln	5 1 62	Iss.
G-18122 Southern Gas Co.	Cement	Okla.	Caddo	5 1 62	Iss.
G-18726 Transwestern Pipeline Co.	Ellis County Area	Okla.	Ellis	2 23 62	Wtd.
G-19289 Texas Gas Transmission Co.	Carterville	La.	Bossier*	6 4 62	Iss.
CI60-587 Colorado Interstate Gas Co.	Hugoton	Kans.	Haskell	4 17 62	Iss.
CI60-657 Texas Gas Transmission Corp.	Calhoun	La.	Ouachita	4 17 62	Iss.
CI60-771 Plateau Natural Gas Co.	Basil*	Kans.	Kingman*	1 17 62	Wtd.
CI61-801 Warren Petroleum Corp.	East Panhandle	Tex.	Collingsworth	6 4 62	Iss.
CI61-913 El PasoNatural Gas Co.	Jalmat	N. Mex.	Lea	3 23 62	Iss.
CI61-914 El Paso Natural Gas Co.	Jalmat	N. Mex.	Lea	3 23 62	Iss.
CI61-915 El Paso Natural Gas Co.	Jalmat	N. Mex.	Lea	3 23 62	Iss.
CI61-1413 Cities Service Gas Co.	Hugoton	Kans.	Finney	1 8 62	Iss.
CI61-1431 TranswesternPipeline Co.	Kermit	Tex.	Winkler	2 21 62	Iss.
CI61-1585 El Paso Natural Gas Co.	Jalmat	N. Mex.	Lea	5 23 62	Iss.
CI61-1705 Cities Service Gas Co.	Guymon-Hugoton	Okla.	Texas	3 23 62	Iss.
CI62-77 Cities Service Gas Co.	Aetna	Kans.	Barber	3 23 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Socony Mobil Oil Co., Inc—Con.					
CI-62-230 Arkansas Louisiana Gas Co.	W. Marlow	Okla	Stephens	4 17 62	Iss.
CI-62-362 Panhandle Eastern Pipe Line Co.	Kismet Area	Kans	Seward	4 17 62	Iss.
Socony Mobil Oil Co. Inc., Operator:					
CI61-1404 El Paso Natural Gas Co.	Signal Peak	Tex	Culberson	1 8 62	Iss.
Socony Mobil Oil Co., Inc., Operator, et al.:					
G-17246 Natural Gas Products Co. of America.	Abell	Tex	Pecos	5 1 62	Iss.
G-17247 Natural Gas Products Co. of America.	Abell	Tex	Pecos	5 1 62	Iss.
G-17248 Natural Gas Products Co. of America.	Abell	Tex	Pecos	5 1 62	Iss.
G-17249 Natural Gas Products Co. of America.	Abell	Tex	Pecos	5 1 62	Iss.
G-17250 Natural Gas Products Co. of America.	Abell	Tex	Pecos	5 1 62	Iss.
CI60-107 Southern Gas Co	North Cement	Okla	Caddo	5 29 62	Iss.
Sohio Petroleum Co.:					
CI61-780 Cities Service Gas Co.	Northeast Waynoka Pool.	Okla	Woods	6 4 62	Iss.
CI61-1662 Natural Gas Pipeline Co. of America.	East Camrick	Okla	Beaver	1 8 62	Iss.
CI62-596 Panhandle Eastern Pipe Line Co.	Mocane Pool	Okla	Beaver	4 17 62	Iss.
Sondau Oil & Gas Co., Inc., et al.:					
CI62-938 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla	Major	3 30 62	Iss.
The Southeastern Drilling Corp., et al.:					
CI60-72 United Gas Pipe Line Co.	Cabeza Creek Area	Tex	Goliad	5 25 62	Iss.
Southern Gas Co.:					
G-17860 Cities Service Gas Co.	North Cement	Okla	Caddo	5 1 62	Iss.
Southern Triangle Oil Co.:					
CI62-480 Hope Natural Gas Co.	New Milton District.	W. Va	Doddridge	4 17 62	Iss.
CI62-887 Hope Natural Gas Co.	New Milton District.	W. Va	Doddridge	6 4 62	Iss.
Southern Union Production Co.:					
G-18580 El Paso Natural Gas Co.	Aztec	N. Mex	San Juan	6 18 62	Dis.
CI60-782 Southern Union Gathering Co.	Blanco	N. Mex	San Juan	6 18 62	Dis.
Southland Royalty Co.:					
CI61-1214 West Texas Gathering Co.	Emperor Deem	Tex	Winkler	5 7 62	Iss.
CI61-1735 Panhandle Eastern Pipe Line Co.	Wil Area	Kans	Edwards*	3 23 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCERS, DOCKET NO. AND PURCHASERS	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Southwest Gas Producing Co., Inc.:					
CI61-1731 Arkansas Louisiana Gas Co.	Vixen	La.	Caldwell	1 29 62	Iss.
Southwest Natural Production Co.:					
G-15460 United Gas Pipe Line Co.	Ada Area	La.	Bienville	3 21 62	Iss.
G-19112 United Gas Pipe Line Co.	Calhoun Area	La.	Ouachita	3 21 62	Iss.
CI61-409 Arkansas Louisiana Gas Co.	North Colquitt	La.	Claiborne	1 29 62	Iss.
Southwest Natural Production Co., et al.:					
CI61-1396 Texas Eastern Transmission Corp.	North Choudrant	La.	Lincoln	1 29 62	Iss.
Southwest Production Co.:					
CI61-1057 El Paso Natural Gas Co.	San Juan	N. Mex.	San Juan	2 21 62	Iss.
CI62-120 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	3 23 62	Iss.
CI62-122 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	3 23 62	Iss.
CI62-830 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	6 4 62	Iss.
CI62-831 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	6 4 62	Iss.
C. C. Spikes:					
CI62-512 Cities Service Gas Co.	Hugoton	Kans.	Finney	6 4 62	Iss.
Robert B. Stallworth, Jr.:					
CI61-1732 Equitable Gas Co.	Salt Lick District	W. Va.	Braxton	1 29 62	Iss.
CI62-42 United Fuel Gas Co.	Union District	W. Va.	Clay	2 21 62	Iss.
CI62-804 Hope Natural Gas Co.	Salt Lick* Districts	W. Va.	Braxton*	6 4 62	Iss.
Fred W. Stalnaker, et al.:					
CI61-97 Hope Natural Gas Co.	Freemans Creek District	W. Va.	Lewis	1 8 62	Iss.
Standard Oil Co. of Texas, Division of California Oil Co.:					
CI62-78 El Paso Natural Gas Co.	Escrito-Gallup Pool.	N. Mex.	Rio Arriba	2 21 62	Iss.
CI62-134 Valley Gas Transmission Inc.	East Alter Mesa No. 7.	Tex.	Brooks	5 23 62	Iss.
Steeple Oil & Gas Corp., et al.:					
CI61-1186 Phillips Petroleum Co.	Undesignated	Tex.	Sherman	5 29 62	Iss.
Stekoll Panhandle, Ltd., Partnership:					
CI61-1203 Northern Natural Gas Co.	Mocane	Okla.	Beaver	1 29 62	Iss.
Stekoll Petroleum Corp.:					
CI60-302 El Paso Natural Gas Co.	Undesignated	N. Mex.	Rio Arriba	5 25 62	Iss.
CI60-445 Southern Union Gathering Co.	Undesignated	N. Mex.	San Juan	5 25 62	Iss.
CI60-468 El Paso Natural Gas Co.	San Juan Area	N. Mex.	Rio Arriba	5 25 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Stelbar Oil Corp., Inc.:					
CI60-292 Wunderlich Development Co.	Warren B Lease	Kans.	Cowley	5 29 62	Iss.
CI62-781 Wunderlich Development Co.	Undesignated	Kans.	Sumner	5 29 62	Iss.
Stevens & Gunn:					
CI60-761 Hope Natural Gas Co.	Sheridan District	W. Va.	Calhoun	6 8 62	Dis.
D. W. Stiles, D. U. Price, & B. H. Keyes:					
CI61-1217 El Paso Natural Gas Co.	Fruitland & Pictured Cliffs.	N. Mex.	San Juan	1 8 62	Iss.
Estate of J. B. Stoddard, Operator, et al.:					
CI61-1335 Coastal States Gas Producing Co.	Fitzsimmons	Tex.	Duval	5 23 62	Iss.
Floyd W. Stone, et al.:					
CI61-1311 Equitable Gas Co.	Central District	W. Va.	Doddridge	1 29 62	Iss.
Stonestreet Lands Co.:					
CI61-59 South Penn Natural Gas Co.	DeKalb District	W. Va.	Gilmer	1 8 62	Iss.
CI61-951 Hope Natural Gas Co.	Smithfield District	W. Va.	Roane	3 26 62	Iss.
CI61-1424 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	1 8 62	Iss.
CI61-1479 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	1 8 62	Iss.
CI61-1669 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	1 8 62	Iss.
CI61-1763 Hope Natural Gas Co.	Smithville District	W. Va.	Roane	1 29 62	Iss.
CI62-293 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	5 29 62	Iss.
Gordon Street, Inc.:					
G-17459 El Paso Natural Gas Co.	Spraberry Trend	Tex.	Glasscock	5 1 62	Iss.
C. A. Stricklin, et al.:					
CI62-386 South Penn Oil Co.	Union District	W. Va.	Ritchie	3 26 62	Iss.
C. Lewis Stryer & Stanley Yochyn:					
CI61-1423 Equitable Gas Co.	Salt Lake District	W. Va.	Braxton	1 8 62	Iss.
John H. Summerville:					
G-14580 United Natural Gas Co.	Appalachian	Pa.	Clarion	3 26 62	Iss.
Sun Oil Co.:					
G-18737 Natural Gas Pipeline Co. of America.	Camrick	Okla.	Beaver	5 1 62	Iss.
G-18910 Natural Gas Pipeline Co. of America.	Camrick S.E. Gas Pool.	Okla.	Beaver	1 29 62	Iss.
CI61-51 Lone Star Gas Co.	North Oak Hill	Tex.	Rusk	1 8 62	Iss.
CI61-1102 Michigan Wisconsin Pipe Line Co.	Woodward Area	Okla.	Major*	3 7 62	Iss.
CI61-1432 Transwestern Pipeline Co.	Waha	Tex.	Pecos	2 21 62	Iss.
CI61-1788 United Gas Pipe Line Co.	Magee	Miss.	Simpson*	5 29 62	Iss.
CI62-125 Northern Natural Gas Co.	North Harper Ranch.	Kans.	Clark	3 26 62	Iss.
CI62-165 Natural Gas Pipeline Co. of America.	South East Boyd	Okla.	Beaver	4 17 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER[2], DOCKET NO. AND PURCHASER[3]	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Sun Oil Co—Continued					
CI62-275 Northern Natural Gas Co.	John Creek	Tex.	Hutchinson	5 29 62	Iss.
CI62-387 Arkansas Louisiana Gas Co.	Vixen	La.	Caldwell	3 26 62	Iss.
CI62-470 Arkansas Louisiana Gas Co.	Manziel	Tex.	Wood	4 17 62	Iss.
CI62-580 Arkansas Louisiana Gas Co.	South Marlow	Okla.	Stephens	4 17 62	Iss.
CI62-1381 El Paso Natural Gas Co.	North Jameson-Strawn.	Tex.	Mitchell*	6 7 62	Rej.
Sunray Mid-Continent Oil Co.:					
G-14288 Northern Natural Gas Co.	Hugoton	Kans.	Finney	5 29 62	Iss.
G-15199 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex.	Lea	5 29 62	Iss.
G-15278 Northern Natural Gas Co.	Elmwood	Okla.	Beaver	1 18 62	Wtd.
G-15468 West Lake Natural Gasoline Co.	Nena Lucia	Tex.	Noland	5 29 62	Iss.
G-15520 Natural Gas Pipeline Co. of Amer[a]ica.	Camrick	Okla.	Beaver	5 29 62	Iss.
G-16010 Northern Natural Gas Co.	Harper Ranch	Kans.	Clark	5 29 62	Iss.
G-16134 Natural Gas Pipeline Co. of America.	Hugoton	Okla.	Texas	5 29 62	Iss.
G-16716 Texas Gas Transmission Corp.	Carlton Area	La.	Ouachita	5 29 62	Iss.
G-17032 Natural Gas Pipeline Co. of America.	Camrick	Okla.	Beaver	5 29 62	Iss.
G-17489 United Gas Pipe Line Co.	E. Cabeza	Tex.	Goliad	5 29 62	Iss.
G-17558 Sinclair Oil & Gas Co.	Murray-Rust	Tex.	Tom Green	5 29 62	Iss.
G-18294 Texas Gas Transmission Corp.	Blackburn	La.	Claiborne*	5 29 62	Iss.
G-18614 Colorado Interstate Gas Co.	Hugoton	Kans.	Kearny	5 29 62	Iss.
G-19060 N. C. Ginther	Bijou	Colo.	Morgan	5 29 62	Iss.
G-19409 Panhandle Eastern Pipe Line Co.	South Hopewell	Kans.	Pratt	5 29 62	Iss.
G-20092 Arkansas Louisiana Gas Co.	Rocky Mount	La.	Bossier	5 29 62	Iss.
CI60-42 United Gas Pipe Line Co.	North Laward	Tex.	Jackson	5 29 62	Iss.
CI60-84 Phillips Petroleum Co.	Azalea	Tex.	Midland	5 29 62	Iss.
CI60-239 Cities Service Gas Co.	Woodward	Okla.	Woodward	5 29 62	Iss.
CI60-305 Arkansas Louisiana Gas Co.	East Kremlin	Okla.	Garfield	5 29 62	Iss.
CI61-133 Cities Service Gas Co.	Dower	Kans.	Barber	5 29 62	Iss.
CI61-1088 United Gas Pipe Line Co.	Tecula	Tex.	Cherokee	5 29 62	Iss.
CI61-1147 Michigan Wisconsin Pipe Line Co.	Undesignated	Okla.	Woodward*	3 7 62	Iss.
CI61-1229 United Gas Pipe Line Co.	Troup	Tex.	Cherokee	5 29 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Sunray Mid-Continent Oil Co. —Continued					
CI61-1385 Cities Service Gas Co.	Dower	Kans.	Barber	5 29 62	Iss.
CI61-1395 Cities Service Gas Co.	Hugoton	Kans.	Finney	5 29 62	Iss.
CI61-1819 Panhandle Eastern Pipe Line Co.	Mocane Chester Zone.	Okla.	Beaver	5 29 62	Iss.
CI62-286 Cities Service Gas Co.	Hugoton	Kans.	Kearny*	5 29 62	Iss.
CI62-462 Northern Natural Gas Co.	Harper Ranch	Kans.	Clark	5 29 62	Iss.
Sunset International Petroleum Corp., Operator, et al.:					
CI62-711 Panhandle Eastern Pipe Line Co.	Hansford	Tex.	Hansford	5 29 62	Iss.
The Superior Oil Co.:					
CI61-87 Mountain Fuel Supply Co.	Alkali Creek Area	Wyo.	Sweetwater	1 8 62	Iss.
CI61-1608 Cities Service Gas Co.	Northeast Waynoka	Okla.	Woods	3 23 62	Iss.
CI61-1671 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	6 8 62	Dis.
Superior Oil & Gas, Inc.:					
CI62-303 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	5 29 62	Iss.
Sutton Producing Co., Agent, Operator, et al.:					
CI61-1741 Transcontinental Gas Pipe Line Corp.	South East Dilworth Area.	Tex.	McMullen	1 29 62	Iss.
Martin F. Sweeney:					
CI61-1179 Equitable Gas Co.	Court House District.	W. Va.	Lewis	1 8 62	Iss.
George K. Taggart, Jr., Operator, et al.:					
G-15522 United Gas Pipe Line Co.	Woodsboro West*	Tex.	Refugio	3 26 62	Iss.
B. E. Talkington:					
CI62-235 Hope Natural Gas Co.	McClellan District	W. Va.	Doddridge	3 26 62	Iss.
CI62-756 Hope Natural Gas Co.	McClellan District	W. Va.	Doddridge	5 29 62	Iss.
B. E. Talkington, et al.:					
G-15024 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	3 26 62	Iss.
Taylor, W. Howard:					
CI61-1604 Valley Gas Co.	Undesignated	W. Va.	Clay	4 4 62	Wtd.
Tenneco Oil Co.:					
CI62-1289 El Paso Natural Gas Co.	Flora Vista	N. Mex.	San Juan	6 1 62	Rej.
Tex-Star Oil & Gas Corp.:					
CI62-1446 El Paso Natural Gas Co.	Ignacio Mesa Verde	Colo.	La Plata	6 20 62	Rej.
Tex-Star Oil & Gas Corp., et al.:					
CI61-329 Lo-Vaca Gathering Co.	Magnolia Beach	Tex.	Calhoun	3 3 62	Wtd.
CI61-330 Lo-Vaca Gathering Co.	Magnolia Beach	Tex.	Calhoun	6 25 62	Wtd.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Tex-Star Oil & Gas Corp., Operator, et al.:					
G-17049 Coastal States Gas Producing Co.	Donna	Tex	Hidalgo	3 26 62	Iss.
CI61-418 Coastal States Gas Producing Co.	Appling	Tex	Calhoun	5 23 62	Iss.
Texaco Inc.:					
CI60-313 Phillips Petroleum Co.	Hugoton	Tex	Moore	5 29 62	Iss.
CI61-65 Valley Gas Transmission, Inc.	North Fannin	Tex	Goliad	5 23 62	Iss.
CI62-138 El Paso Natural Gas Co.	Eumont	N. Mex	Lea	2 21 62	Iss.
CI62-335 Lone Star Gas Co	Carter-Knox	Okla	Stephens	5 29 62	Iss.
CI62-519 Cities Service Gas Co.	Hugoton	Kans	Kearny	6 4 62	Iss.
CI62-569 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla	Major	3 30 62	Iss.
CI62-842 Panhandle Eastern Pipe Line Co.	Hugoton	Kans	Stevens	6 4 62	Iss.
Texaco Inc., Operator:					
CI60-479 Natural Gas Pipeline Co. of America.	Hansford-Morrow	Tex	Hansford	5 7 62	Iss.
Texaco Seaboard Inc.:					
CI61-1589 Arkansas Louisiana Gas Co.	Lassater	Tex	Marion	1 29 62	Iss.
CI61-1760 Colorado Interstate Gas Co.	Patrick Draw-Desert Springs Area.	Wyo	Sweetwater	1 29 62	Iss.
Texam Oil Corp.:					
G-12107 Gas Gathering Co	Seely	Tex	Live Oak	5 1 62	Iss.
Texas Crude Oil Co., Operator, et al.:					
CI61-1218 Transwestern Pipeline Co.	Worsham	Tex	Reeves	2 21 62	Iss.
Texas Gas Exploration Corp., Operator, et al.:					
CI61-1414 Trunkline Gas Co	Moss Hill	Tex	Liberty	1 8 62	Iss.
CI61-1427 Texas Gas Transmission Corp.	Cartwright	La	Jackson	1 29 62	Iss
Texas National Petroleum Co., Operator, et al.:					
CI61-1507 El Paso Natural Gas Co.	San Juan Basin	N. Mex	San Juan	3 23 62	Iss.
Texas Pacific Coal and Oil Co.:					
G-14407 El Paso Natural Gas Co.#	King Mountain	Tex	Upton	1 29 62	Iss.
CI62-3 El Paso Natural Gas Co.	Langlie-Mattix	N. Mex	Lea	5 7 62	Iss.
Texas Pacific Coal & Oil., Operator, et al.:					
CI61-1582 El Paso Natural Co.	Langlie-Mattix	N. Mex	Lea	1 8 62	Iss.
CI61-1649 Phillips Petroleum Co.	Azalea	Tex	Midland	3 23 62	Iss.
CI62-852 Lone Star Gas Co	Knox	Okla	Grady *	5 7 62	Iss

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Texfel Petroleum Corp., Operator:					
CI61-1117 United Gas Pipe Line Co.	West Jacksonville	Tex	Cherokee	5 7 62	Iss.
Texoma Production Co.:					
CI61-1059 Transwestern Pipeline Co.	Luther Hill	Okla	Ellis	2 21 62	Iss.
CI61-1526 Transwestern Pipeline Co.	Catesby	Okla	Ellis	3 23 62	Iss.
CI61-1527 Transwestern Pipeline Co.	Catesby	Okla	Ellis	3 23 62	Iss.
CI61-1533 Transwestern Pipeline Co.	Northwest Ivanhoe	Okla	Beaver	3 23 62	Iss.
The Texstar Corp., Operator, et al.:					
CI62-537 Cities Service Gas Co.	East Antelope	Kans	Marion	4 17 62	Iss.
Glenn F. Thomas, et al.:					
CI60-193 Panhandle Eastern Pipe Line Co.	Undesignated	Kans	Meade	2 21 62	Iss.
CI61-1269 Panhandle Eastern Pipe Line Co.	Undesignated	Kans	Meade	3 23 62	Iss.
CI62-845 Panhandle Eastern Pipe Line Co.	Undesignated	Kans	Morton	6 4 62	Iss.
Tidewater Oil Co.:					
G-11049 Tennessee Gas Transmission Co.	East Cameron Area	La	Cameron *	1 22 62	Iss.
CI61-86 Arkansas Louisiana Gas Co.	East Kremlin	Okla	Garfield	1 8 62	Iss.
CI61-416 Michigan Wisconsin Pipe Line Co.	Northwest Doby Springs	Okla	Harper	3 12 62	Wtd.
CI61-1206 El Paso Natural Gas Co.	Bloomfield Area	N. Mex	San Juan	5 7 62	Iss.
CI61-1253 Arkansas Louisiana Gas Co.	Lassater	Tex	Marion	5 7 62	Iss.
CI61-1599 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla	Major	3 30 62	Iss.
CI61-1789 Texas Eastern Transmission Corp.	Mercedes	Tex	Hidalgo	1 29 62	Iss.
CI62-185 El Paso Natural Gas Co.	Flora Vista Area	N. Mex	San Juan	5 29 62	Iss.
CI62-987 Northern Natural Gas Co.	Yates Casinghead Gas Plant	Tex	Pecos	6 4 62	Iss.
Bill Tomberlin, Operator, et al.:					
G-19294 Kansas-Nebraska Natural Gas Co., Inc.	Riverside	Colo	Weld	5 1 62	Iss.
Tomlinson-Kathol Inc., Operator, et al.					
CI61-606 Panhandle Eastern Pipe Line Co.	S. W. Haynes	Kans	Stafford	1 29 62	Iss.
Toto Gas Co.:					
CI62-689 Cities Service Gas Co.	Lucien	Colo	Logan	6 4 62	Iss.
CI62-692 Wunderlich Development Co.	Southeast Autwine	Okla	Kay	5 29 62	Iss.
Toto Gas Co., Operator, et. al.:					
CI62-699 Wunderlich Development Co.	Southeast Autwine	Okla	Kay	5 29 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Tower Oil & Gas Co. of Texas:					
CI60-665 El Paso Natural Gas Co.	Spraberry Area*	Tex	Upton	5 29 62	Iss.
CI62-193 North Central Gas Co., et. al.	Shawnee	Wyo	Converse	3 19 62	Iss.
J. C. Trahan Drilling Contractor, Inc.:					
CI62-40 RAF Natural Gas Corp.	Longwood	La*	Caddo*	3 23 62	Iss.
CI62-521 Texas Gas Transmission Corp.	Monroe	La	Union*	4 17 62	Iss.
Gerald T. Tresner:					
CI61-720 Michigan Wisconsin Pipe Line Co.	Laverne	Okla	Harper	3 22 62	Rej.
Trident Corp.:					
CI61-1150 Texas Eastern Transmission Corp.	West Helen Gohlke	Tex	De Witt	5 25 62	Iss.
Trio Oil & Gas Co., Inc.:					
CI61-1800 Hope Natural Gas Co.	New Milton District.	W. Va	Doddridge	2 23 62	Iss.
CI62-717 Hope Natural Gas Co.	West Union District.	W. Va	Doddridge	5 29 62	Iss.
CI62-757 Hope Natural Gas Co.	Grant District	W. Va	Doddridge	5 29 62	Iss.
CI62-768 Hope Natural Gas Co.	Grant District	W. Va	Doddridge	5 29 62	Iss.
CI62-879 Hope Natural Gas Co.	Grant District	W. Va	Doddridge	6 4 62	Iss.
Twin Gas Co.:					
CI62-98 Lone Star Gas Co	Tatums	Okla	Carter	2 21 62	Iss.
Union Gas Associates, Inc.:					
CI62-32 Hope Natural Gas Co.	Freemans Creek District.	W. Va	Lewis	3 23 62	Iss.
Union Drilling Co., Inc.:					
CI62-4 Equitable Gas Co	Hackers Creek District.	W. Va	Lewis	5 7 62	Iss.
CI62-405 Equitable Gas Co	Horner Field Skin Creek District.	W. Va	Lewis	5 7 62	Iss.
CI62-714 Equitable Gas Co	Skin Creek District.	W. Va	Lewis	5 7 62	Iss.
Union Producing Co.:					
CI62-968 The Nueces Co	Agua Dulce	Tex	Nueces	5 14 62	Rej.
Union Producing Co., Operator:					
CI61-335 United Gas Pipe Line Co.	Willow Springs	Tex	Gregg	5 7 62	Iss.
Union Texas Petroleum, et. al.:					
CI61-1655 Oklahoma Natural Gas Gathering Corp., et. al.	Ringwood	Okla	Major	3 30 62	Iss.
United Producing Co., Inc.:					
G-16584 Panhandle Eastern Pipe Line Co.	Hugoton	Kans	Stevens*	5 23 62	Iss.
G-17911 Texas Gas Transmission Corp.	Carlton & Calhoun Areas.	La	Ouachita	3 26 62	Iss.
CI61-1361 Panhandle Eastern Pipe Line Co.	Undesignated	Okla	Texas	1 8 62	Iss.
CI62-477 Northern Natural Gas Co.	Undesignated	Kans	Stevens*	4 17 62	Iss.
CI62-621 United Fuel Gas Co.	Elk District	W. Va	Kanawha	6 4 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
United States Smelting Refining & Mining Co.:					
CI61-1625 Kansas-Nebraska Natural Gas Co., Inc.	Mt. Hope	Colo.	Logan	3 23 62	Iss.
Valley Gas Transmission, Inc.:					
CI61-909 Trunkline Gas Co.	Maetz	Tex.	Goliad	5 31 62	Iss.
Van-Grisso Oil Co.:					
CI62-890 Northern Natural Gas Co.	Laverne	Okla.	Harper	6 4 62	Iss.
J. H. Vandenbark, Operator, et al.:					
G-20055 El Paso Natural Gas Co.	Spraberry Trend	Tex.	Upton	5 1 62	Iss.
Alice M. Vandergrift:					
CI61-887 Carnegie Natural Gas Co.	Union District	W. Va.	Ritchie	5 7 62	Iss.
CI61-1488 Carnegie Natural Gas Co.	Union District	W. Va.	Ritchie	5 1 62	Iss.
Vaughey and Vaughey:					
CI61-1744 El Paso Natural Gas Co.	Basin Dakota*	N. Mex.	Rio Arriba	1 29 62	Iss.
Neven H. Veail, et al.:					
CI62-181 Hope Natural Gas Co.	South West District.	W. Va.	Doddridge	3 23 62	Iss.
CI62-865 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	6 4 62	Iss.
Viersen & Cochran, Operator, et al.:					
CI61-1712 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
S. M. Vockel, Jr., Trustee:					
CI61-337 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	5 31 62	Iss.
T. F. Voiles, et al.:					
G-18575 Panhandle Eastern Pipe Line Co.	Guymon-Hugoton	Okla.	Texas	3 26 62	Iss.
A. H. Wadsworth, Jr.:					
CI62-1380 Claud B. Hamill	Nada	Tex.	Colorado*	6 22 62	Rej.
J. H. Wagner, et al.:					
G-19204 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
G-19205 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
G-19206 Wunderlich Development Co.	Undesignated	Kans.	Cowley	3 26 62	Iss.
Keith F. Walker:					
CI61-1239 Lone Star Gas Co.	South Dixie Area	Okla.	Jefferson	2 21 62	Iss.
Walter Ward, et al.:					
CI61-1197 Hope Natural Gas Co.	Sherman District	W. Va.	Calhoun	3 23 62	Iss.
E. C. Ware, et al.:					
CI61-1115 United Fuel Gas Co.	Tug River District	W. Va.	Mingo	2 21 62	Iss.
Warner & Goebl, et al.:					
CI61-1601 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	1 29 62	Iss.

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NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Ralph L. Warner, et al.:					
CI61-1338 Hope Natural Gas Co.	Collins Settlement District.	W. Va.	Lewis	1 8 62	Iss.
Ed E. Watts:					
CI60-682 El Paso Natural Gas Co.	Jalmat	N. Mex.	Lea	5 23 62	Iss.
William G. Webb:					
G-15692 El Paso Natural Gas Co.	Blanco	N. Mex.	Rio Arriba	5 1 62	Iss.
Dorothea Webber, et al.:					
CI62-295 Hope Natural Gas Co.	Greenbrier District	W. Va.	Doddridge	5 29 62	Iss.
W. A. Wegmann:					
CI61-1697 Texas Eastern Transmission Corp.	Beans Ferry	Miss.	Itawamba	3 23 62	Iss.
J. R. Welch:					
CI61-1234 Equitable Gas Co.	Troy District	W. Va.	Gilmer	5 25 62	Iss.
Wellshire Development Co.:					
CI61-25 El Paso Natural Gas Co.	Fulsher Kutz	N. Mex.	San Juan	2 21 62	Iss.
John L. Welsh, Jr., Operator, et al.:					
G-15705 Coastal States Gas Producing Co.	North Willman	Tex.	San Patricio	1 29 62	Iss.
Welsh Oil & Gas Co., Operator:					
G-20503 Valley Gas Production, Inc.	Maetze Field Area	Tex.	Goliad	5 29 62	Iss.
Welsh Oil & Gas, Operator, et al.:					
CI61-1740 United Gas Pipe Line Co.	North Laward	Tex.	Jackson	1 8 62	Iss.
Western Natural Gas Co., et al.:					
CI61-1249 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	3 23 62	Iss.
Western Natural Gas Co., Operator, et al.:					
CI61-1454 El Paso Natural Gas Co.	Hiway Area*	N. Mex.	San Juan	2 21 62	Iss.
Western Oil Refining Co.:					
CI62-936 El Paso Natural Gas Co.	North Labarge	Wyo.	Sublette	6 4 62	Iss.
Westland Oil Development Corp.:					
CI61-1165 The Shamrock Oil & Gas Corp.	Panhandle	Tex.	Hutchinson	5 7 62	Iss.
Carl J. Westlund, Inc., Operator, et al.:					
G-18873 Northern Natural Gas Co.	Brinkard	N. Mex.	Lea	5 1 62	Iss.
Olin B. Wetzel, Agent:					
CI61-1278 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	2 21 62	Iss.
Olin B. Wetzel:					
CI61-1686 Equitable Gas Co.	West Union District.	W. Va.	Doddridge	3 26 62	Iss.
CI62-868 Hope Natural Gas Co.	Cove District	W. Va.	Doddridge	6 4 62	Iss.
Olin B. Wetzel, et al.:					
CI61-1083 Hope Natural Gas Co.	West Union District.	W. Va.	Doddridge	1 29 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Wheelock Oil Co., et al.:					
CI61-1251 Tennessee Gas Transmission Co.	La Reforma	Tex.	Starr	5 7 62	Iss.
Wheless Drilling, Operator:					
CI60-697 Texas Gas Transmission Corp.	Minden	La.	Webster	5 7 62	Iss.
J. S. Wheless, Jr.:					
G-16823 United Gas Pipe Line Co.	Baxterville	Miss.	Lamar*	5 1 62	Iss.
W. M. Wheless, et al.:					
G-16824 United Gas Pipe Line Co.	Baxterville	Miss.	Lamar*	5 1 62	Iss.
Robert F. White, Operator, et al.:					
CI61-69 Panhandle Eastern Pipe Line Co.	Grunner Pool	Kans.	Stafford	1 8 62	Iss.
Wilcox Oil Co.:					
CI61-717 Michigan Wisconsin Pipe Line Co.	Woodward Area	Okla.	Woodward*	3 7 62	Iss.
Robert K. Wilkoff:					
CI62-155 United Fuel Gas Co.	Stafford District	W. Va.	Mingo	5 29 62	Iss.
George E. Willett:					
CI62-909 El Paso Natural Gas Co.	Undesignated	N. Mex.	San Juan	6 4 62	Iss.
Kidd Williams Production Corp., Operator, et al.:					
CI61-1746 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
CI61-1747 Oklahoma Natural Gas Gathering Corp., et al.	Ringwood	Okla.	Major	3 30 62	Iss.
J. C. Williamson, Operator:					
G-18248 Pioneer Gathering System, Inc.	Addie	Tex.	Crockett	3 23 62	Iss.
J. C. Williamson, Operator, et al.:					
CI61-214 El Paso Natural Gas Co.#	Willrode	Tex.	Upton	1 29 62	Iss.
Wilshire Oil Co. of Texas, Operator, et al.					
CI62-988 El Paso Natural Gas Co.	Basin Dakota	N. Mex.	San Juan	6 4 62	Iss.
W. C. Wilson, et al.:					
CI61-1824 Equitable Gas Co.	Otter District	W. Va.	Braxton	5 29 62	Iss.
Wise Operating, Inc. of Tyler, Texas, Operator, et al.:					
CI61-1178 United Gas Pipe Line Co.	Mt. Selman	Tex.	Cherokee	3 23 62	Iss.
Robert L. Wolff:					
CI61-1212 Equitable Gas Co.	Court House District	W. Va.	Lewis	1 8 62	Iss.
Robert L. Wolff, et al.:					
CI61-1248 Equitable Gas Co.	Court House District	W. Va.	Lewis	2 21 62	Iss.
CI62-323 Equitable Gas Co.	Court House District	W. Va.	Lewis	3 26 62	Iss.
Wolfson Oil Co.:					
CI62-376 El Paso Natural Gas Co.	Jalmat	N. Mex.	Lea	3 26 62	Iss.

See footnotes at end of table, p. 1464.

NEW SERVICE CERTIFICATES—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Woodman-Iannitti Oil Co., Operator,et al.:					
CI62-141 Cities Service Gas Co.	Undesignated	Kans.	Barber	5 29 62	Iss.
Woods Exploration & Producing Co., Inc., Operator, et al.:					
CI61-1583 Texas Eastern Transmission Corp.	Marrs-McLean	Tex.	Jefferson	1 29 62	Iss.
Woods Exploration Co.:					
CI62-19 Cities Service Gas Co.	Southeast Sterling	Okla.	Comanche	2 21 62	Iss.
Woodson Oil Co.:					
CI61-996 Michigan Wisconsin Pipe Line Co.	Cedardale	Okla.	Woodward	3 7 62	Iss.
R. H. Worden, Agent:					
CI62-269 United Fuel Gas Co.	Cedar Creek	Ky.	Pike	5 1 62	Iss.
Wright Gas Co.:					
G-10553 South Penn Oil Co.	DeKalb District	W. Va.	Gilmer	5 1 62	Iss.
Wunderlich Development Co., Operator:					
CI61-1460 Cities Service Gas Co.	East Billings	Okla.	Noble	5 23 62	Iss.
George L. Yaste:					
CI62-119 Equitable Gas Co.	Clay District	W. Va.	Ritchie	3 23 62	Iss.
CI62-170 Carnegie Natural Gas Co.	Center District	W. Va.	Gilmer	5 29 62	Iss.
Yates Petroleum Corp., Operator, et al.:					
CI61-993 Transwestern Pipeline Co.	Atoka-Penn	N. Mex.	Eddy	2 21 62	Iss.
Oley Yeager:					
G-18941 South Penn Oil Co.	Mullins Farm Bulgar.	W. Va.	Lincoln	5 1 62	Iss.
Charles E. Young, Operator, et al.:					
G-20100 Hope Natural Gas Co.	Grant District*	W. Va.	Ritchie*	5 25 62	Iss.
Charles E. Young, et al.:					
CI61-146 Equitable Gas Co.	Clay District	W. Va.	Ritchie	5 7 62	Iss.
John F. Younger, et al.:					
CI61-1522 Phillips Petroleum Co.	Azalea	Tex.	Midland	1 8 62	Iss.
Zephyr Oil Co.:					
CI61-1080 United Gas Pipe Line Co.	Henderson	Tex.	Rusk	1 29 62	Iss.
Frank Zickefoose:					
G-19342 Equitable Gas Co.	Horn Creek	W. Va.	Gilmer	5 1 62	Iss.
CI61-1543 Equitable Gas Co.	Troy District	W. Va.	Gilmer	5 7 62	Iss.
Frank Zickefoose, et al.:					
CI61-1120 Hope Natural Gas Co.	Troy District	W. Va.	Gilmer	1 29 62	Iss.

See footnotes at end of table, p. 1464.

PRODUCER APPLICATIONS FOR ABANDONMENT OF SERVICE DISPOSED OF DURING THE PERIOD JANUARY 1, 1962 THROUGH JUNE 30, 1962

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Amerada Petroleum Corp.:					
CI62-945 United Gas Pipe Line Co.	Gottschalk	Tex.	Goliad	6 8 62	Iss.
The Atlantic Refining Co.:					
CI61-1656 Transcontinental Gas Pipe Line Corp.	Lac Des Allemandes.	La.	St. Charles	1 12 62	Iss.
Baker & Taylor Drilling Co.:					
CI62-1066 Phillips Petroleum Co.	West Pampa	Tex.	Gray	6 8 62	Iss.
Jenova Bissett:					
CI62-449 Equitable Gas Co.	Grant District	W. Va.	Wetzel	6 8 62	Iss.
J. Frank Brown:					
CI61-1660 United Fuel Gas Co.	Magnolia District	W. Va.	Mingo	1 12 62	Iss.
N. G. Busch:					
CI62-461 South Penn Oil Co.	Undesignated	W. Va.	Wirt*	4 19 62	Iss.
B. G. Byars Drilling Co.:					
CI61-470 Lone Star Gas Co.	Manziel	Tex.	Wood	3 19 62	Iss.
F. A. Callery, Inc., et al.:					
CI60-652 United Fuel Gas Co.	Luling	La.	St. Charles	3 21 62	Iss.
Carter-Jones Drilling Co., Inc., Operator, et al.:					
CI62-246 Tennessee Gas Transmission Co.	Tobasco	Tex.	Hidalgo	6 8 62	Iss.
Continental Oil Co.:					
CI61-483 Arkansas Louisiana Gas Co.	Driscoll	La.	Bienville	3 19 62	Iss.
Ira J. Cox:					
CI62-935 The Manufacturers Light & Heat Co.	Shamrock Farms Area.	Pa.	Fayette	6 8 62	Iss.
Scott Duffield, et al.:					
CI61-381 Hope Natural Gas Co.	Washington District.	W. Va.	Calhoun	1 8 62	Iss.
Earlsboro Oil & Gas Co., Operator, et al.:					
CI62-747 Cities Service Gas Co.	Witerock	Okla.	Noble	6 8 62	Iss.
Orville Eberly, Agent:					
CI62-282 Cumberland and Allegheny Gas Co.	Mt. Pleasant Park	Md.	Garrett	6 8 62	Iss.
CI62-807 The Manufacturers Light & Heat Co.	Summit	Pa.	Fayette	6 8 62	Iss.
Phillip Fowler, et al.:					
CI62-529 Transcontinental Gas Pipe Line Corp.	Tyran Area	Tex.	Bee	6 8 62	Iss.
Delbert Goff, et al.:					
CI61-281 Hope Natural Gas Co.	Sherman District	W. Va.	Calhoun	1 8 62	Iss.
CI61-1753 Hope Natural Gas Co.	Troy District	W. Va.	Gilmer	6 8 62	Iss.
Great Western Drilling Co.:					
CI62-814 Northern Natural Gas Co.	Undesignated	Kans.	Pawnee	6 8 62	Iss.

See footnotes at end of table, p. 1464.

ABANDONMENT APPLICATIONS—Continued

PRODUCER[2], DOCKET NO. AND PURCHASER[3]	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Gulf Oil Corp.:					
CI62-133 Lone Star Gas Co.	Southeast Aylesworth Pool.	Okla.	Bryan	6 8 62	Iss.
CI62-556 Transcontinental Gas Pipe Line Corp.	Southeast Rayne	La.	Lafayette	6 8 62	Iss.
Haines Gas Co.:					
CI62-245 South Penn Oil Co.	Curry District	W. Va.	Putnam	6 8 62	Iss.
G. Scott Hammonds, Agent, et al.:					
CI62-413 Arkansas Louisiana Gas Co.	Texas Rodessa	Tex.	Marion	6 8 62	Iss.
R. T. Harris, Operator, et al.:					
CI62-270 Tennessee Gas Transmission Co.	Bethany	Tex.	Panola	1 12 62	Iss.
Dan J. Harrison, Operator, et al.:					
CI62-279 Texas Gas Corp.	Robbinson Lake	Tex.	Chambers	3 19 62	Iss.
Dan J. Harrison, Jr.:					
CI62-278 Texas Eastern Transmission Corp.	Undesignated	Tex.	Liberty	3 19 62	Iss.
Ernest Hayhurst, et al.:					
CI61-435 Hope Natural Gas Co.	DeKalb District	W. Va.	Gilmer	1 8 62	Iss.
Paul E. Heinselman:					
CI61-1754 Hope Natural Gas Co.	Jefferson District	W. Va.	Pleasants	6 8 62	Iss.
Hercules Oil & Gas:					
CI61-444 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	1 12 62	Iss.
Humble Oil & Refining Co.:					
CI61-688 El Paso Natural Gas Co.	Wyatt-Ellenburger	Tex.	Crockett	3 19 62	Iss.
Hassie Hunt Trust:					
CI61-1515 Transcontinental Gas Pipe Line Corp.	Outside Island	La.	Vermilion	6 8 62	Iss.
Lamar Hunt Trust, Estate:					
CI61-1455 Unit Gas Co., Inc.	Palo Blanco	Tex.	Brooks	1 12 62	Iss.
N. B. Hunt:					
CI61-1456 Unit Gas Co., Inc.	Palo Blanco	Tex.	Brooks	1 12 60	Iss.
Kerr-McGee Oil Industries, Inc., Operator, et al.:					
CI62-111 Cities Service Gas Co.	Happy Valley Gasoline Plant No. 11.	Okla.	Lincoln	6 8 62	Iss.
Lario Oil & Gas Co.:					
CI62-924 Kansas-Nebraska Natural Gas Co., Inc.	Kammerer Gas Unit.	Colo.	Morgan	6 8 62	Iss.
Charles W. Louchery:					
CI60-606 Hope Natural Gas Co.	Undesignated	W. Va.	Harrison	6 8 62	Iss.
Luray Land, Inc.:					
CI62-758 Hope Natural Gas Co.	Freemans Creek District.	W. Va.	Lewis	6 8 62	Iss.
CI62-759 Hope Natural Gas Co.	Undesignated	W. Va.	Braxton	6 8 62	Iss.

See footnotes at end of table, p. 1464.

ABANDONMENT APPLICATIONS—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
McCall Drilling Co., Inc.:					
CI61-223 Hope Natural Gas Co.	Center District	W. Va.	Gilmer	1 8 62	Iss.
CI61-473 Hope Natural Gas Co.	Center District	W. Va.	Gilmer	1 8 62	Iss.
CI61-474 Hope Natural Gas Co.	Center District	W. Va.	Gilmer	1 8 62	Iss.
Meridith & Co.:					
CI61-1314 Texas Gas Corp.	East Mazes	Tex.	Chambers	6 8 62	Iss.
Mideastern Gas Co., Inc.:					
CI62-223 Hope Natural Gas Co.	Mannington District.	W. Va.	Marion	1 12 62	Iss.
Bob Miner:					
CI61-998 United Gas Pipe Line Co.	Old Refugio	Tex.	Refugio	1 8 62	Iss.
Moyers Oil & Gas Co.:					
CI61-1821 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	1 8 62	Iss.
D. C. Mullenix, Attorney-in-Fact:					
CI61-1695 Hope Natural Gas Co.	Union District	W. Va.	Ritchie	1 8 62	Iss.
Murphy Corp.:					
CI61-1374 Arkansas Louisiana Gas Co.	North Ruston	La.	Lincoln	1 12 62	Iss.
CI62-478 El Paso Natural Gas Co.	South Rangely	Colo.	Rio Blanco	6 8 62	Iss.
Owens-Illinois Gas Co.:					
CI62-14 Hope Natural Gas Co.	Paw Paw District	W. Va.	Marion	3 19 62	Iss.
Phillips Petroleum Co.:					
CI61-412 United Gas Pipe Line Co.	Bayou-Piquant	La.	Terrebonne	1 8 62	Iss.
CI61-1657 Tennessee Gas Transmission Co.	Calallen	Tex.	Nueces	6 8 62	Iss.
CI62-795 Lone Star Gas Co.	Cruce	Okla.	Stephens	6 8 62	Iss.
Placid Oil Co.:					
CI61-1459 Transcontinental Gas Pipe Line Corp.	Raceland	La.	LaFourche	1 12 62	Iss.
Plymouth Gas Co.:					
CI62-404 South Penn Oil Co.	McComas District	W. Va.	Cabell	6 8 62	Iss.
Point Corp., Operator, et al.:					
CI62-1069 Coastal States Gas Producing Co.	North William	Tex.	San Patricio	6 8 62	Iss.
Pontiac Refining Corp.:					
CI61-423 Transcontinental Gas Pipe Line Corp.	Goree	Tex.	Bee	6 8 62	Iss.
Pratt Gas Co.:					
CI62-403 South Penn Oil Co.	McComas District	W. Va.	Cabell	6 8 62	Iss.
R. A. D. Corp.:					
CI61-436 Hope Natural Gas Co	Union District	W. Va.	Harrison	1 12 62	Iss.
St. Clair Oil Co.:					
CI61-464 Hope Natural Gas Co.	Murphy District	W. Va.	Ritchie	1 12 62	Iss.
Shell Oil Co.:					
CI61-407 Tennessee Gas Transmission Co.	Stedman Island	Tex.	Nueces	1 12 62	Iss.

See footnotes at end of table, p. 1464.

ABANDONMENT APPLICATIONS—Continued

PRODUCER[2], DOCKET NO. AND PURCHASER[2]	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Siboney-Caribbean Petroleum Co.:					
CI62-149 C. V. Lyman	Mary	Tex.	Jim Wells	3 19 62	Iss.
Sinclair Oil & Gas Co.:					
CI62-430 Kansas-Nebraska Natural Gas Co., Inc.	Divide	Colo.	Logan	6 8 62	Iss.
Socony Mobil Oil Co., Inc.:					
CI61-1603 Pioneer Gathering Systems, Inc.	Clayton Ranch	Tex.	Crockett	6 8 62	Iss.
CI62-800 Trunkline Gas Co.	Southeast Fulton	La.	Beauregard	6 8 62	Iss.
Sohio Petroleum Co.:					
CI61-343 Tennessee Gas Transmission Co.	South Deckers Prairie Area.	Tex.	Montgomery	1 12 62	Iss.
Southern Coast Corp., et al.:					
CI62-320 Tennessee Gas Transmission Co.	Undesignated	Tex.	Webb[3]	4 10 62	Iss.
Southwestern Exploration Consultants, Inc., Operator:					
CI62-925 Arkansas Louisiana Gas Co.	West Dilworth	Okla.	Kay	6 8 62	[4] Iss.
CI62-926 Arkansas Louisiana Gas Co.	West Dilworth	Okla.	Kay	6 8 62	Iss.
Spartan Gas Co.:					
CI62-310 United Fuel Gas Co.	Poca District	W. Va.	Kanawha	1 8 62	Iss.
State Gas Co., Inc.:					
CI62-1083 Consolidated Gas Utilities Corp.	Vernon	Okla.	Kay	6 8 62	Iss.
Stonetex Oil Corp.:					
CI62-975 Tennessee Gas Transmission Co.	West Calaboose	Tex.	San Patricio	6 8 62	Iss.
Sunray Mid-Continent Oil Co.:					
CI61-308 United Gas Pipe Line Co.	North McFaddin	Tex.	Victoria	1 8 62	Iss.
CI61-408 Arkansas Louisiana Gas Co.	Driscoll	La.	Bienville	1 8 62	Iss.
CI62-373 Tennessee Gas Transmission Co.	North Agua Dulce	Tex.	Nueces	5 7 62	Iss.
Sunray Mid-Continent Oil Co., Operator, et al.:					
CI62-368 Tennessee Gas Transmission Co.	Wyrick	Tex.	Refugio	6 8 62	Iss.
The Superior Oil Co.:					
CI62-399 Cities Service Gas Co.	Rhodes	Kans.	Barber	6 8 62	Iss.
CI62-448 United Gas Pipe Line Co.	Ewing	Tex.	San Patricio	6 8 62	Iss.
Ben J. Taylor:					
CI62-832 Panhandle Eastern Pipe Line Co.	Pleasant Valley	Kans.	Ford	6 8 62	Iss.
Texaco, Inc.:					
CI61-937 Coastal States Gas Producing Co., et al.	North Fitzsimmons	Tex.	Duval	6 8 62	Iss.
Texaco Seaboard, Inc.:					
CI61-1500 Transcontinental Gas Pipe Line Corp.	Lac Des Allemandes.	La.	St. Charles	1 12 62	Iss.

See footnotes at end of table, p. 1464.

ABANDONMENT APPLICATIONS—Continued

PRODUCER#, DOCKET NO. AND PURCHASER#	FIELD	STATE	COUNTY	DISPOSITION DATE	DISPOSITION [1]
Texas Gulf Producing Co.:					
CI62-68 Trunkline Gas Co	S.E. Fulton	La	Beauregard	1 8 62	Iss.
Tidewater Oil Co.:					
CI61-1728 Hope Natural Gas Co.	Second Bayou	La	Cameron	6 8 62	Iss.
Union Producing Co.:					
CI61-1609 Unit Gas Co., Inc	Palo Blanco	Tex	Brooks	1 12 62	Iss.
Alice M. Vandergrift, et al.:					
CI62-528 Hope Natural Gas Co.	Courthouse District	W. Va	Lewis	6 8 62	Iss.
Weir Walker, et al.:					
CI62-643 Hope Natural Gas Co.	Cass District*	W. Va	Monongalia	5 8 62	Iss.
Dick Wegener and C. E. Davis:					
CI61-1685 Lone Star Gas Co	Nellie	Okla	Stephens	3 19 62	Iss.
E. C. Wilson:					
CI61-1694 Hope Natural Gas Co.	Troy District	W. Va	Gilmer	6 8 62	Iss.
S. E. Wilson Lease:					
CI61-184 Hope Natural Gas Co.	Lafayette District	W. Va	Pleasants	1 8 62	Iss.
Wolf Pen Oil & Gas Co.:					
CI62-178 Hope Natural Gas Co.	Union District	W. Va	Ritchie	1 8 62	Iss.
Wysong Gas Co.:					
CI62-392 South Penn Oil Co.	Undesignated	W. Va	Lincoln	6 8 62	Iss.

*Indicates that other fields, counties, or States are also included.

#Producers' and Purchasers' name may include et al., trustee, agent, or additional names on certain dockets.

[1] Iss., issued; Wtd., withdrawn; Rej., rejected; Dis., dismissed.